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U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY DELIVERY & ENERGY RELIABILITY

Smart Grid Investment Grant Program Final Report

December 2016

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EXECUTIVE SUMMARY

In 2009, the U.S. Department of Energy (DOE) launched the Smart Grid Investment Grant (SGIG) program, funded by $3.4 billion invested through the American Recovery and Reinvestment Act of 2009 (ARRA) to modernize the nation's electricity system. Projects began in 2010, and the program was completed in 2015.

While the SGIG program has published an extensive series of technical reports throughout the program on SmartGrid.gov, this final report summarizes the major SGIG achievements, key project results, and lessons learned across the smart grid landscape, which included:

- Synchrophasor technologies on electric transmission systems.
- Distribution automation (DA) technologies and systems, including advanced sensors and self-healing controls.
- Advanced metering infrastructure (AMI), including smart meters and two-way communications networks.
- Customer systems, including in-home displays (IHD), programmable communicating thermostats (PCT), and direct load control devices (DLC) that enable utilities to offer time-based rates and incentives.

The SGIG program stimulated near-term economic growth, created jobs, and enhanced the reliability and resilience of the nation's electric grid through the deployment of smart grid technologies, tools, and practices. To catalyze continued investment in grid modernization, the SGIG program analyzed the impact, costs, and benefits of smart grid technologies and shared the data to help reduce the financial and technical risks for follow-on smart grid efforts.

SGIG projects were competitively selected and required a minimum 50 percent cost share, attracting an additional $4.5 billion in private, local investment during an economic downturn—bringing the total SGIG investment to $7.9 billion. Because of this public-private partnership, many utilities accelerated their grid modernization plans by as many as 10 years, or were able to broaden the scope of planned projects to benefit more customers.

SGIG projects helped to rapidly mature the smart grid vendor marketplace. By 2012, SGIG had created 12,000 direct jobs in the smart grid ecosystem of manufacturers, IT, and technical service providers, and created another 35,000 full-time equivalent positions throughout vendor supply chains.[1] As the program was expressly designed to help utilities tackle the learning curve of new technologies and functions, the projects demonstrated smart grid technology benefits and cost savings that were expected but not yet proven—and documented results and lessons learned to educate industry peers.[2]

The U.S. electricity system reached key grid modernization targets up to four years faster than expected during SGIG. By 2012, U.S. utilities had already surpassed the program's 2015 target for nationwide smart meter deployments; by 2015, nearly half of U.S. customers had smart meters—almost 65 million—a milestone that would not have been met until 2019 based on pre-ARRA utility plans and proposals.[3]

[1] U.S. Department of Energy, Economic Impact of Recovery Act Investments in the Smart Grid (April 2013).
[2] SmartGrid.gov serves as a library of SGIG project information and smart grid technology results, benefits, and lessons learned.
[3] The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (September 2009).

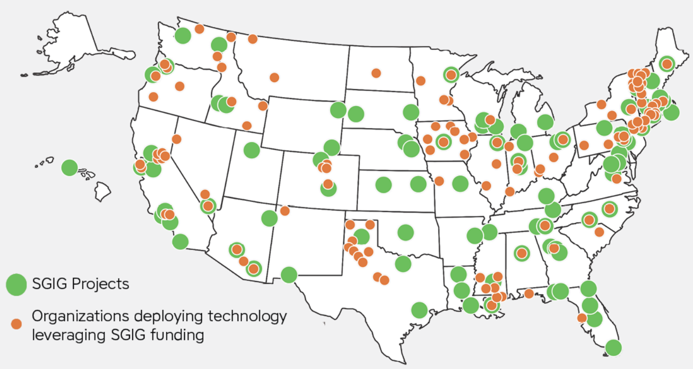
SMART GRID INVESTMENT GRANT (SGIG) PROGRAM OVERVIEW

SGIG PROGRAMS AND FUNDING

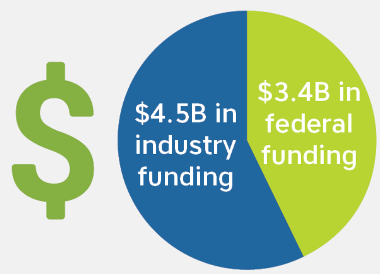
99 competitively selected projects

228 participating utilities and organizations

6 years (2010-2015)

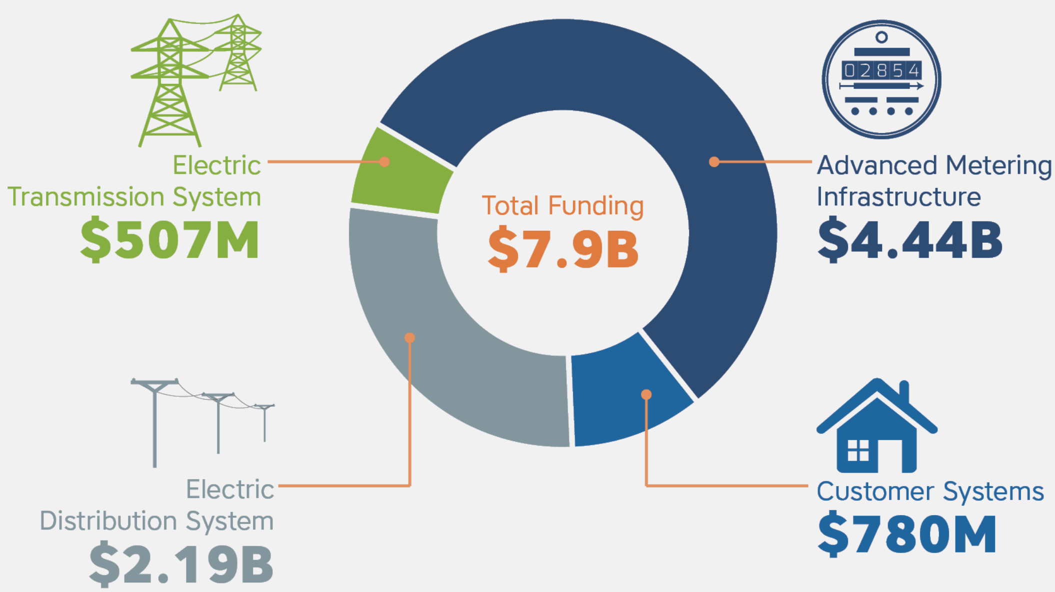


$7.9B public/private investment



ARRA funding was matched or exceeded dollar for dollar by recipients.

SGIG PROJECT TECHNOLOGY AREAS



SGIG TECHNOLOGY DEPLOYMENTS

ELECTRIC TRANSMISSION SYSTEM

1,380 networked synchrophasors contributed to a more than **10** fold increase in North American synchrophasors from 2007 to 2015.

CUSTOMER SYSTEMS

Nearly **700,000** customer devices

ELECTRIC DISTRIBUTION SYSTEM

82,000 intelligent, automated devices

ADVANCED METERING INFRASTRUCTURE

16M SGIG smart meters about **33%** of the **49M** total smart meters installed in the U.S. from 2010 – 2014

DEMONSTRATED SMART GRID TECHNOLOGY BENEFITS

- Increased wide-area visibility and faster situational awareness in the transmission system to prevent local disturbances from cascading into major regional blackouts.
- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.
- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.
- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.
- More effective equipment monitoring and preventative maintenance that reduce operating costs and the likelihood of equipment failures, make more efficient use of capital assets, and resulting in fewer outages.
- Lower peak demand and higher power factors for improved asset utilization and deferral of capital investments in capacity additions.
- Reduced costs for metering and billing from fewer truck rolls, labor savings, more accurate and timely bills, and fewer customer disputes.
- Improved customer control to manage electricity consumption, costs, and bills from new customer tools (e.g., web portals and PCTs) and programs (e.g., time-based rates, incentives, and DLC) for shifting demand from peak to off-peak periods.

SGIG was the largest program of a broader $4.5 billion ARRA-funded grid modernization effort managed by the DOE Office of Electricity Delivery and Energy Reliability (OE).[4] This portfolio included the Smart Grid Demonstration Program, the Smart Grid Workforce Training Program, projects for regional electric transmission planning and renewable and distributed energy integration, and development of smart grid cybersecurity and interoperability standards in collaboration with the National Institute of Standards and Technology.

Major Findings and Key Results

The SGIG program helped jumpstart grid modernization by proving that an array of smart grid technologies, tools, and techniques can work effectively in utility applications and improve grid planning and operations in a variety of ways. The data collected from the projects provided evidence of grid improvements and financial benefits at different scales and utility environments.

For many participating utilities, SGIG provided an opportunity to gain confidence and experience while resolving both expected and unforeseen issues. Several utilities used SGIG funding to test the integration of new technologies and systems on a small scale, while others used the opportunity for large-scale or system-wide deployments—creating variation in costs and impacts. Many of the projects implemented some but not all of the smart grid capabilities that new devices made available, with the plan to activate more functions over time, depending on results.

DOE published technology results and lessons learned on SmartGrid.gov throughout the program to reduce investment uncertainty for utilities, regulators, and other key decision-makers.[5] Because many of the technologies and systems were new to most of the utilities, evaluating results was often a challenge, particularly when establishing baselines and estimating before-and-after grid impacts. Unprecedented volumes of data challenged utilities to develop new methods, models, and more advanced data analytics. Nevertheless, information developed under SGIG provided quantitative evidence, insights, and lessons learned for guiding future investments in grid modernization, as highlighted in the major findings below.

Synchrophasor deployments improve transmission system visibility and help grid operators prevent large-scale outages.[6]

The SGIG program deployed more than 1,300 phasor measurement units (PMUs) to enhance visibility by measuring and delivering data 100 times faster than conventional technologies, permitting grid operators to identify and correct for system instabilities, such as frequency and voltage oscillations, and operate transmission lines at higher capacity levels. The SGIG projects marked the first time that many transmission owners and operators installed modern, production-grade PMUs on an operational scale—transitioning synchrophasor technology from a research and off-line analysis tool to one that actively enhances real-time operations.

Synchrophasors also proved valuable in detecting and diagnosing transmission and generation issues before they become threats to the power system. The American Transmission Company **identified and replaced a potentially failing transformer, avoiding an extended transmission substation outage**. The New York Independent System Operator (NYISO) **detected a malfunctioning automatic voltage regulator controller** in one generating station and a failed power system stabilizer in another.

[4] DOE OE, "ARRA Grid Modernization Investment Highlights," fact sheet (October 2015).
[5] See Appendix A. SGIG Project Information, Case Studies, and Key Reports for a detailed list of publications.
[6] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

Before SGIG, there were fewer than 200 PMUs in the U.S. transmission system, used primarily for research. By 2015, there were more than 1,700 networked synchrophasors, providing visibility across nearly 100 percent of the U.S. transmission system at varying degrees of resolution. Grid operators across the country are beginning to use this synchrophasor data to enhance situational awareness and wide-area monitoring, improve state estimator models for better understanding of real-time grid conditions, improve dynamic planning models for better understanding of how power systems respond to grid disturbances, and provide more thorough and accurate forensic analysis of disturbances and outages.

In 2008, 14 transmission lines taken out of service by Hurricane Gustav formed an electrical island. Entergy's **synchrophasors enabled operators to detect the island and then diagnose and mitigate instabilities within that island, preventing a blackout of New Orleans and Baton Rouge.** This was a motivator for Entergy to triple its number of PMUs to 49 and expand its synchrophasor system capabilities under its SGIG project.

DA and AMI improve reliability with fewer and shorter outages, faster service restoration, and customer savings.[7]

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 customers, DA operations during major storms saved one utility's customers on a 14-feeder segment $1.2 million in one year. Fully automated switching and validation typically resulted in greater reliability improvements than operator-initiated remote switching with manual validation.

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.**

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. As a result, SGIG projects were able to:

- Remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information—**often shaving hours or days off restoration time following major storms**. By integrating DA with AMI, utilities reduced outage duration, limited customer inconvenience, and reduced labor hours and truck rolls for outage diagnosis and restoration.
- Isolate disruptions and restore downstream customers within seconds by automating distribution tasks such as fault detection and feeder switching. For *each* outage event, **utilities reduced the number of affected customers by as much as 55 percent and reduced the total customer minutes of interruption by up to 53 percent** using "self-healing" FLISR capabilities.
- In 2013, 3 utilities reported **System Average Interruption Frequency Index (SAIFI) improvements of 17–58 percent** from pre-deployment baselines.

[7] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).

Utilities facing regular, severe weather events and storm-induced outages often have greater incentives for using AMI for outage management than those that do not.[8] AMI data integration with other information and management systems, including geographic information systems, enabled utilities to create detailed outage maps, and in some cases posted these maps on utility websites to keep the public informed on service restoration progress.

Automated controls for voltage and reactive power management improve efficiency and power factors and reduce energy consumption and costs.[9]

Automated voltage regulation and power factor correction enabled SGIG utilities to reduce peak demand, use assets more efficiently, defer capital investments, and improve power quality for customers. Several utilities used conservation voltage reduction (CVR) techniques to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption, especially during peak demand periods.

Automated power factor correction provided new capabilities for managing reactive power flows and boosting power quality. Several utilities improved power factors to near unity through integrated volt/VAR controls, and one utility reduced reactive power requirements by about 10 to 13 percent over one year.

Several utilities found **CVR to produce 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 reduce power plant emissions.

Voltage monitoring provides another promising benefit stream to include in business case analysis of AMI investments. Utilities can use AMI voltage monitoring capabilities to enhance the effectiveness of automated controls for voltage and reactive power management, particularly for CVR programs.

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.**

Equipment health sensors prevent equipment failures, reduce outages, and lower O&M costs.[10]

Installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters provides real-time alerts for abnormal equipment conditions and data for new analysis tools for utility engineers to improve preventative maintenance and equipment repairs 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.

[8] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[9] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[10] Ibid.

Operational efficiencies from AMI and DA deliver cost savings and improve customer service and satisfaction.[11]

CenterPoint Energy reported total **AMI cost savings of more than $61 million from 2012-2014.** Tamper detection functions alone prevented revenue losses exceeding $450,000 in 2012 and $130,000 in 2014.

AMI and DA projects together reduced an estimated 17,510 metric tons of CO_2-equivalent emissions by eliminating nearly 14 million truck rolls and 71.8 million vehicle-miles[12] that were previously required to read meters, detect outages and confirm restoration, manually detect faults, inspect equipment health, and conduct manual feeder switching. Nine SGIG utilities together avoided $6.2 million in distribution operations costs over a one-year period[13] and eight utilities avoided $1.46 million in switching costs over three years.[14] AMI operations from 19 projects also cumulatively saved $316 million in O&M costs over a three-year period—an average of $16.6 million per project reporting.[15]

- Large-scale deployments and utilities with low customer densities or geographically dispersed territories had the greatest savings potential. Utilities with AMI are now able to fulfill remote service connection and disconnection orders in hours instead of days.
- Many utilities improved billing accuracy, reduced customer complaints, and used AMI data to resolve billing disputes faster. AMI enabled some utilities to proactively identify and notify customers of unusual usage patterns in advance of bills.
- Pre-pay billing plans helped customers to better manage energy consumption and costs. Several utilities improved revenue collection and cost recovery by implementing pre-pay billing programs. AMI capabilities for tamper and theft detection also enhanced revenue collection and cost recovery.

AMI and customer systems improve time-based rate, incentive, and DLC programs that reduce peak demand, power consumption, and bills for many participating customers.[16]

Oklahoma Gas & Electric reported **average annual electricity savings of $191.78 for participating residential customers** and $570.02 for commercial customers.

More than 417,000 customers participated in one or more time-based rate or incentive programs under SGIG, including critical peak pricing (CPP), variable peak pricing (VPP), time-of-use (TOU) pricing, and critical peak rebates (CPR). In particular, a subset of 10 utilities participated in the Consumer Behavior Studies (CBS)[17], which evaluated different recruitment strategies, rate structures, and customer systems for customer acceptance, retention, and response.

- CBS utilities implemented programs in which customers reduced their peak demand by up to 23.5 percent.
- Several utilities found that PCT automation enabled greater peak demand reductions than manual responses.

[11] Ibid; DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[12] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014.
[13] Distribution operations cost savings data reported by 9 DA utilities from April 2013 to September 2014.
[14] Switching cost savings data reported by 8 DA utilities from April 2011 to March 2014.
[15] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[16] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016); DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).
[17] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

- IHDs had minimal impact on demand reductions, and in many cases, participating customers declined to use them or used them for a short period of time.

DA and AMI improve integration of distributed energy resources (DER) for grid planning and operations.[18]

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%.

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 and integrated automated dispatch systems on small DER installments. A small number also tested two types of DERs: thermal energy storage for commercial and government buildings, and charging stations for electric vehicles. These projects gained valuable insight into future grid impacts of DER technologies and load patterns.

SGIG cybersecurity policies improve utility business and technology protection practices to address emerging threats.

As top priority for every aspect of the program from its inception, cybersecurity under SGIG accelerated progress toward a more secure grid not only for participants but for the entire electric power industry. Smart digital devices added new IP-based access points to the grid, making customer privacy and cybersecurity paramount to smart grid success. All SGIG recipients were required to implement comprehensive cybersecurity plans and build cybersecurity into their policies, technologies, and business practices. SGIG expert cyber teams augmented these measures with over 300 onsite reviews to monitor project progress, including cybersecurity implementation. Two cybersecurity information exchange meetings held in 2011 and in 2012 promoted peer-to-peer sharing of best practices and lessons learned among SGIG projects.[19] Through this intensive effort, many SGIG utilities—particularly smaller ones—enhanced cybersecurity practices across their entire system and continue to use the SGIG cybersecurity plan as a model.

Lessons and Conclusions

The SGIG projects showed that further deployment of smart grid technologies, tools, and techniques can achieve favorable grid impacts and benefits for customers and utilities. Achieving these impacts and benefits involved changes in communications systems, workforce training, and business practices, especially for systems integration and cybersecurity.

Comprehensive planning for communications systems enables multiple and improved smart grid functions. Greater communications network capabilities are the backbone of grid modernization. Several SGIG utilities adopted long-term, comprehensive smart grid strategies that included building communications networks with large capacities to handle future smart grid applications, and with high bandwidth to accommodate additional services beyond electricity metering—such as gas and water metering and internet services. Network upgrades included many types of systems based on local conditions and needs including RF-based local mesh networks, high-bandwidth fiber optic cables, powerline carrier systems, and one-off microwave repeater solutions. With such systems in place, utilities can

[18] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[19] DOE OE, "2012 DOE Smart Grid Cybersecurity Information Exchange," workshop report (June 2013).

deploy smart grid devices faster and at full scale, and unlock additional capabilities from their investments in smart devices.

Effective systems integration is paramount for successful smart grid operations. Multiple information management and control systems all need access to a wide variety of new data streams to effectively accomplish smart grid functions. SGIG utilities installed new management information systems for meter data, distribution operations, outages, customer information, and enterprise service buses to promote interfacing between these systems. Systems integration proved to be one of the most significant challenges for many SGIG utilities, particularly for those deploying smart grid for the first time. Integration often required developing customized software for data processing, error checking, and coding.

Smarter grids require workforce training and new business practices, particularly for cybersecurity. Many of the SGIG projects made organizational changes in metering, customer service, marketing, and distribution operations, particularly in areas that require enhanced levels of integration of both new information systems and job functions. In many instances, these changes involved workforce training programs to develop new skillsets in areas such as database management, information systems, data analytics, and cybersecurity. Cybersecurity was a cornerstone of the SGIG program from its onset and required utility staff to develop and implement new cybersecurity policies, plans, and practices throughout the lifecycle of each project. This includes new levels of oversight and awareness for cybersecurity by utility managers and increased levels of time and resources devoted to it.

Future Directions and Next Steps

The majority of SGIG utilities are building on project results and planning for more technology deployments, offering successful pilot programs to more customers, and improving the integration of smart grid technologies, tools, and techniques within their electricity delivery systems. Several opportunities and challenges are guiding future grid modernization investments:

- **Many utilities have untapped opportunities to maximize the capabilities of new smart grid technologies**. For example, many utilities installed smart meters but have not yet used the embedded capabilities to monitor customer voltage levels, or have combined voltage monitoring with automated controls for voltage and reactive power management. Planned follow-on activities include expanding deployments to larger portions of service territories, expanding communications networks, and integrating various information management systems to realize untapped automation capabilities.

- **Vast amounts of new data require development of new data exchange and management capabilities, including new models and analysis tools to unlock the full value of smart grid technologies.** Smart meters, PMUs, and other devices provide timely and granular data at large volumes that require investments in high-bandwidth communications networks and advanced data analytics to better automate controls and inform operator decisions. These advanced capabilities are necessary to integrate large amounts of distributed and renewable generation, reduce susceptibility of the system to destabilizing events, and bring together utility functions for generation, transmission, distribution, and demand-side programs.

- **Cybersecurity systems, processes, and personnel continue to be a critical component of utility operations**. Smart grid technologies provide many benefits but also open up opportunities for adversaries to attack critical infrastructure. Generation and utility operators need to continue efforts to identify and deploy protections against ever-evolving cybersecurity threats.

- **The electric power industry is exploring new business models and planning requirements to address grid modernization and integration of distributed energy resources.** Increases in DER adoption requires new approaches to resource planning, economic and environmental regulations, and market development to sustain reliability and boost resilience while involving consumers and third-parties in electricity management and generation to a much greater extent than before. Policy makers, regulators, consumer advocates, utilities, and other service providers need to continue working closely to ensure grid capabilities keep pace with changing requirements for DER integration, reliability, and security.

In addressing these and other technology, policy, and market challenges, DOE continues to be an important contributor to grid modernization through research, development, demonstration, analysis, and technology transfer activities. **SGIG showed what can be achieved in grid modernization through public-private partnerships involving DOE and the electric power industry.** New technologies are driving changes on multiple fronts and the need continues for strong national efforts to modernize the grid.

Following SGIG, grid modernization remains important national priority for DOE programs. For example, DOE recently launched a **new Grid Modernization Initiative (GMI) and released a Grid Modernization Multi-Year Program Plan (MYPP)** of proposed activities for achieving a more modern, secure, sustainable, and reliable grid. DOE plans to work toward these goals through a comprehensive set of programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 national laboratories and regional networks, is assisting DOE in developing and implementing the activities in the MYPP.[20]

[20] DOE, *Grid Modernization Multi-Year Program Plan* (November 2015).

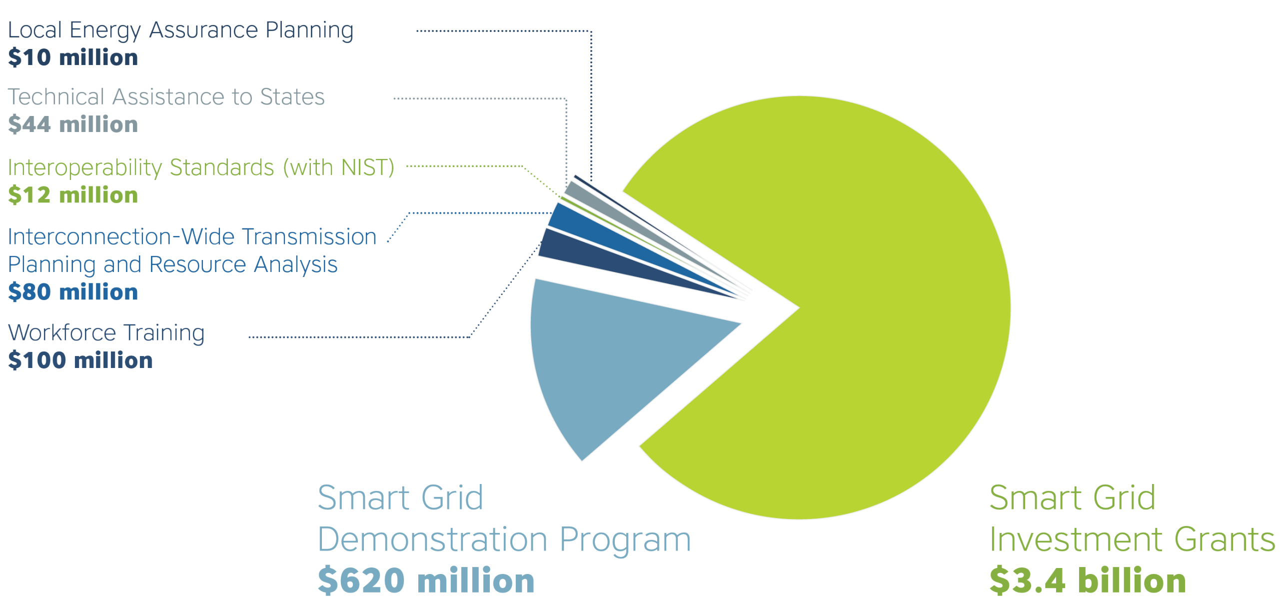
1 | INTRODUCTION

The U.S. Department of Energy's Smart Grid Investment Grant (SGIG) program was launched in 2009 amidst a major industry transition in how U.S. electricity is generated, sold, delivered, and used. The nation's growing clean energy economy is changing the sources and characteristics of electricity generation, creating a more dynamic system. Further complexity is added as distributed energy resources (DER) such as solar panels become more ubiquitous, creating two-way energy flows and changing customers from passive consumers to active market participants. Weather-related power disruptions are on the rise at a time when resilience has never been more important. The economy's reliance on reliable power continues to grow as industries, businesses, and communities increasingly perform their most basic functions using digital technologies and automated systems.

As a result, grid operators increasingly require more flexible, agile control to maintain historic levels of reliability while adding advanced capabilities to a century-old grid design. Intelligent, digital technologies hold promise to dynamically optimize grid operations, rapidly detect and mitigate disturbances, integrate diverse resources and demand response, enable customers to manage their electricity use and participate in markets, and provide strong protection against physical and cyber risks. **Yet in 2009, these advanced smart grid technologies were nascent**—still largely unproven and without an established history of performance or return on investment. Meanwhile, a significant economic downturn had slowed the rise in electricity consumption and restricted resources for grid upgrades, requiring an exceptionally strong business case for new technology investments.

The American Recovery and Reinvestment Act of 2009 (ARRA) provided $4.5 billion to the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) to jumpstart electric grid modernization at a critical time. DOE OE initiated the SGIG program and complementary grid modernization programs, including the Smart Grid Demonstration Program (SGDP), the Workforce Training and Development Program, interconnection transmission planning, state and local energy assurance planning, and standards development for systems interoperability and cybersecurity (Figure 1.1).

FIGURE 1.1 U.S. DEPARTMENT OF ENERGY ARRA GRID MODERNIZATION INVESTMENTS



Together, the ARRA grid modernization program activities represent one of the largest federal investments in new technologies for electric power delivery since the Rural Electrification Act of 1935. OE's grid modernization programs spurred innovation and investment in smart grid technologies, tools, and techniques—implementing the vision of the Energy Investment and Security Act of 2007 (EISA). Title XIII, Section 1301 of EISA made it U.S. policy to support grid modernization to maintain a reliable and secure electricity infrastructure and meet future demand growth. Section 1306 further authorized a "Federal Matching Fund for Smart Grid Investment Costs" to support adoption of smart metering, sensing, and control devices and software systems in electric transmission, distribution, and customer systems.

This report provides the final progress update for the SGIG program—including work completed since the second SGIG Progress Report, published in October 2013—and summarizes key overall program impacts, benefits, and lessons learned. While this report focuses solely on the results of the SGIG program, information about the other ARRA grid modernization programs can be found at SmartGrid.gov.

1.1 | SGIG: A Shared Investment in Cutting-Edge Technologies

The SGIG program received $3.4 billion in federal funding and was the cornerstone of DOE's ARRA grid modernization effort. SGIG funds were matched or exceeded by a minimum dollar-for-dollar industry cost share. The program was designed specifically to catalyze investment in the nation's electric power grid, demonstrate the effectiveness of advanced technologies and systems, and advance knowledge sharing among market participants and decision makers.

The SGIG program's 99 competitively selected projects involved 228 utilities and other organizations in nearly every state and touched every region of the country. Projects deployed advanced technologies, tools, and techniques for transmission, distribution, smart metering, and customer systems.

At program initiation, SGIG grant recipients planned to contribute an additional $4.4 billion, for a total budget of $7.8 billion. During the course of the projects, several teams decided to increase their funding share, raising total SGIG project expenditures to $7.9 billion.

DOE OE leads the federal government's efforts to modernize the electric grid, enhance the security and reliability of the nation's energy infrastructure, and facilitate recovery from disruptions to energy supply. Over the last five years, DOE OE managed the SGIG program to successfully achieve its original objectives. The SGIG program:

- Accelerated deployment of smart grid technologies across the transmission and distribution systems.
- Empowered customers with information to better manage their electricity consumption and costs.
- Measured the impacts and benefits of smart grid technologies to reduce uncertainty for decision makers and attract additional capital to further advance grid modernization.
- Accelerated the development and deployment of effective cybersecurity protections for smart grid technologies and systems.

1.2 | A Pivotal Time for Smart Grid Investments

The SGIG investments came at a pivotal time in the electricity industry, when a multitude of factors converged to drive the need for advanced smart grid technologies, along with the information, communications, and control systems that can transmit and interpret the large amounts of digital information they create. Smart grid deployments are being driven in part by five key trends that continue today:

- **Changing mixes and characteristics of electricity generation sources** are shifting electricity generation from relatively few large central station plants to many smaller and sometimes variable generators. Electricity generation from natural gas and variable renewable sources is growing, while coal-based generation is declining. Energy efficiency and renewable energy policies are providing incentives for utilities and customers to install distributed generation and building energy management equipment.
- **Changing demand loads in retail electricity markets** result from demographic and economic shifts, the adoption of more energy-efficient end-use technologies, growing consumer participation, broader electrification, and use of electronic converters (rather than induction motors) on appliances and equipment. Residential consumers and commercial and industrial companies are also seeking greater control over how their electricity is produced and delivered.
- **Increased commercial availability of smart grid technologies** that can better manage progressively challenging loads offers operators new capabilities to manage complex power systems.
- **Expectations are growing for a resilient and responsive power grid** in the face of more frequent and intense weather events, cyber and physical attacks, and interdependencies with natural gas and water systems. Weather-related power disruptions are on the rise at a time when dependence on the electric grid by other critical infrastructures is growing.
- **Aging electricity infrastructure requires new technologies** to enable better failure detection, upgrade capabilities, and improve cybersecurity. While the extant electricity infrastructure provided the backbone for a healthy economy for several decades, design and capabilities of existing infrastructure date from a fundamentally different technological era, and the capabilities and scope of deployed technology are often insufficient to meet today's rapidly evolving needs.

1.3 | SGIG Data Collection and Sharing Reduces Uncertainty

Each of the 99 SGIG projects reported to DOE key data to help determine the impact and value of the new technologies and systems they implemented. Each SGIG project collected two types of metrics: 1) build metrics, including the number of installed devices and their costs, and 2) a set of impact metrics (e.g., avoided meter operations costs) that assessed the effects of the new technologies and systems on grid operations and business practices. From the outset, DOE worked with recipients to design a metrics and benefits analysis process[21] that would allow it to collect and assess four key components (see Figure 1.2):

- ***Assets*** – The device or technology installed (e.g., smart meters)
- ***Functions*** – The function that asset performs (e.g., remote service connections/disconnections and demand management)
- ***Impacts*** – The impact that function has on grid operations (e.g., reduced truck rolls and lower peak demands)
- ***Benefits*** – The value of that impact to customers and utilities, monetized when possible (e.g., lower operating costs and reduced customer bills)

[21] Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1 (December 2012).

FIGURE 1.2 SGIG ANALYSIS PROCESS

Because SGIG projects involved not only new technologies but also new business practices, procedures, and system designs, DOE analysis also included regular assessment of **lessons learned and best practices** from the SGIG projects. Sharing results and lessons learned throughout the course of the five-year program served to reduce uncertainty around technology effectiveness and performance for decision makers and investors.

1.4 | Smart Grid Drives Economic Growth and Reduces Emissions

The SGIG program attracted more than $4 billion in private, local investment and provided a stimulus for business development and job growth during an economic downturn. A 2013 DOE report analyzed the economic impacts of the SGIG and SGDP investments made from August 2009 through March 2012.[22] DOE estimated that for every $1 million spent in the first three years of the SGIG and SGDP programs, U.S. GDP increased by $2.5 to $2.6 million.[23] In the same time period, SGIG and SGDP project investments supported about 47,000 full-time-equivalent jobs, many which were highly technical and high paying.[24]

Smart grid investments that improve operational and energy efficiency also reduce environmental emissions. SGIG deployments produced environmental benefits that are expected to grow as deployments expand. SGIG utilities reported that they:

1. Reduced an estimated 17,510 metric tons of CO_2-equivalent emissions by eliminating nearly 14 million truck rolls and 71.8 million vehicle-miles[25] that were previously required to read meters, detect outages and confirm restoration, manually detect faults, inspect equipment health, and conduct manual feeder switching.
2. Avoided hundreds of metric tons of CO_2 emissions from electricity saved by using CVR techniques that reduced line losses and lowered peak demands, and by using customer systems and time-of-use rates that reduced peak and overall electricity use.
3. Increased use of clean and distributed energy resources and integrated electric vehicle charging stations.

The SGIG program helped to create a more intelligent grid with automated controls, better reliability and resilience, less expensive operations and maintenance, greater levels of clean energy, improved cybersecurity and interoperability, and higher levels of customer engagement in managing electricity consumption and costs.

[22] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[23] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[24] DOE OE, *Economic Impact of Recovery Act Investments in the Smart Grid* (April 2013).
[25] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014.

1.5 | U.S. Smart Grid Advanced Beyond SGIG Targets

When the SGIG program began, the Office of Management and Budget identified several key targets for smart grid technology deployment and performance for the SGIG program. The targets were designed to track progress and help measure the success of the SGIG program in accelerating smart grid investment. Industry outcomes and key results from the SGIG projects, also described in greater detail throughout this report, demonstrate that the SGIG program met or exceeded each target (see Table 1.1). A check indicates targets that were met; a check-plus indicates targets that were exceeded.

TABLE 1.1 ASSESSMENT OF PRE-SGIG SMART GRID ADVANCEMENT TARGETS

	Smart Grid Target (Set in 2010)	Met?	Post-SGIG Results
DEPLOYMENT TARGETS	**By 2013,** 26 million consumers will be equipped with smart meters **(compared to 8 million in 2010).**	✓+	There were **53.3 million U.S. smart meters by 2013** and **64.7 million smart meters by 2015**. [26] SGIG utilities installed 16.3 million of those smart meters.
	By 2013, 23,000 distribution circuits will have automated equipment **(compared to approximately 15,000 circuits in 2010).**	✓+	There were **>49,000 distribution circuits with voltage optimization** by 2013.[27] SGIG utilities upgraded about 6,500 distribution circuits.
	By 2013, 1043 networked phasor measurement units will be installed **(compared to 166 in 2010) providing** nearly 100% coverage of the transmission system **(as measured by the percentage of the power flow visible to synchrophasor technology).**	✓+	By 2015, there were **>1,700 networked synchrophasors** installed throughout the transmission system, resulting in **near 100% visibility.**[28] ARRA funding was responsible for 1,380 of those PMUs.
PERFORMANCE TARGETS	**By 2015, customers with smart meters, enabling technologies, and dynamic pricing will realize a** 5% reduction in their annual electricity bills **and will have** reduced their peak demand by 5%**.** **(Peak demand reduction will also be stated in terms of an equivalent deferral of generation capacity, in megawatts; consumer cost savings will also be calculated.)**	✓+	Customers enrolled in dynamic pricing programs piloted at 10 utilities in the SGIG Consumer Behavior Studies saw annual **customer savings of $5 to >$500** (depending on the type of rate) and **reduced peak demand by up to 23.5%**. One SGIG utility is deferring capital investment in 170 MW of peaking generation by expanding enrollment in its time-based rate program.[29]

[26] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[27] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[28] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[29] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016).

PERFORMANCE TARGETS

Smart Grid Target (Set in 2010)	Met?	Post-SGIG Results
By 2015, utilities will realize a 10% decrease in annual operations and maintenance costs **for distribution circuits with automated equipment.**	✓	**AMI services saved about $316 million in labor and O&M costs for 19 SGIG utilities over 3 years, while DA savings from avoided switching costs totaled >$1.46 million** for 8 SGIG utilities over 3 years. During severe storms, the avoided costs from reducing restoration time—for both utilities and customers—were also substantial.[30]
By 2015, customers on distribution circuits with distribution automation will experience a 5% average reduction in the length of their power outages**.**	✓+	SGIG utilities **reduced the duration of an outage event by up to 53%** (total customer minutes of interruption) and **reduced the number of affected customers by as much as 55%** using DA technologies.[31]
By 2015, 50% of transmission operators will have planning and/or operating procedures **that incorporate synchrophasor measurements.**	✓	12 of the 14 synchrophasor project participants are now using synchrophasor data to **inform operations** and 11 are using the data to **inform planning**. ARRA participants are responsible for more than 80% of U.S. load.[32]
By 2015, the deployment of advanced control technology will result in a 5% reduction in energy wasted (line losses) **in distribution circuits.** **(The reduction in energy wasted will also be stated in terms of an equivalent reduction in the emissions of CO2, NOX and SOX.)**	✓	Several **utilities saw total energy savings of 2-4% on feeders with voltage optimization, and reduced line losses by substantial amounts**. (Emissions savings for line losses were not individually measured.)
By 2015, customers with smart meters, enabling technologies, and dynamic pricing will have reduced emissions of CO_2, NOX and SOX associated with their electricity consumption by 1%**.** **(The contribution of peak load shifting and total load reduction will be calculated.)**	✓	DA and AMI operations **reduced CO_2-equivalent emissions by 17,510 metric tons** over a nearly 4-year reporting period by avoiding truck rolls previously required to read meters, detect outages, and confirm restoration.[33]

[30] 19 SGIG projects reporting; DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[31] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[32] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[33] DA operations avoided 197,000 truck rolls (reported by 16 projects) and 3.4 million vehicle-miles (reported by 18 projects) from 2011 to 2015. AMI operations avoided 13,785,708 truck rolls (reported by 42 projects) and 68,374,295 vehicle-miles (reported by 39 projects) from summer 2011 to winter 2014. DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (September 2016); DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).

2 | MAJOR FINDINGS AND KEY RESULTS FROM SMART GRID INVESTMENTS

From 2010 to 2015, DOE and industry joined forces to deploy smart devices and systems on an accelerated timescale by sharing the financial and technological risks typical of immature technologies.

In 2010, the SGIG program began to deploy millions of nascent smart grid technologies at a critical time—the vendor landscape was small, the anticipated benefits and savings were not yet proven on a large scale, and the recent economic downturn had slowed growth in demand and constrained utility resources for investment in new technologies.

> "Without the funding, we would have waited to let the technology mature in the industry. We would have deployed the technology at a slower pace, which would have delayed the benefits to our customers."
>
> MIKE GODOROV, MANAGER OF PPL'S SMART GRID PROJECT
>
> SOURCE: PPL ELECTRIC UTILITIES, "BUILDING A SMARTER DISTRIBUTION SYSTEM IN PENNSYLVANIA," 2012.

Most SGIG utilities estimated that the SGIG program accelerated their grid modernization investment plans by 2–10 years, delivering substantial benefits to customers and the economy sooner. For many, the 50 percent cost share created the business case to deploy some advanced technologies years earlier than planned or to broaden the scope of their near-term upgrade plans to benefit more customers.

From 2009 to 2015, SGIG utilities:

- **Installed more than 1,300 synchrophasors in the transmission system and spurred the deployment of hundreds more using private funds** on the heels of the program's early successes. This resulted in near 100 percent visibility in the transmission system by 2015 and contributed to a more than tenfold increase in installed synchrophasors in North America between 2007 and 2015.
- **Deployed more than 16.3 million smart meters,** representing about 33 percent of the 49 million smart meters installed nationwide between 2009 and 2014. An estimated 58.5 million smart meters are now installed nationwide, accounting for more than 40 percent of electricity customers.[34]
- **Installed nearly 82,000 intelligent devices to upgrade about 6,500 distribution circuits,** many serving customers with critical business needs for fewer and shorter outages. While this accounts for just about 3 percent of total U.S. circuits,[35] many utilities upgraded the worst-performing substations and feeders first to achieve substantial reliability improvements.

The U.S. electricity system reached key grid modernization targets up to four years faster than expected during SGIG. Targets set at the outset of the ARRA predicted that U.S. utilities would install 26 million smart meters by 2013 and 40 million by 2015.[36] More than 43 million U.S. customers had smart meters by 2012—surpassing the 2015 target

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[34] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[35] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[36] White House, "Progress Report: The Transformation to a Clean Energy Economy," Memorandum for the President from the Vice President (December 15, 2009).

three years early—and installations reached more than 64.7 million by 2015.[37] Today, nearly half of U.S. customers now have smart meters—a milestone that would not have been met until 2019 or later based on pre-ARRA utility plans and proposals.[38]

DOE reported interim SGIG costs, results, grid impacts, and key lessons on SmartGrid.gov, creating a wealth of public information designed to reduce technology performance uncertainty and help utilities more confidently assess the business case for smart grid deployments industry-wide. Sharing early project successes helped utilities justify and commit more private funds to smart grid deployments outside the program.

Analysis of SGIG technology costs, benefits, and performance also helped inform state utility regulators and other policy makers, who play a crucial role in grid modernization by setting policy objectives, approving rates and technology investment plans, overseeing cost recovery strategies, and protecting customers from potential harm, including data privacy and cybersecurity. DOE representatives shared early project results at industry conferences, regional regulatory meetings, and National Association of Regulatory Utility Commissioners (NARUC) meetings.

The SGIG program successfully demonstrated that smart grid technologies are able to deliver the types of benefits and cost savings that were anticipated but not yet proven on a large scale in a variety of settings.

Smart grid technology impacts varied from project to project, and not all utilities realized similar or equally significant benefits. This was primarily because utilities chose to deploy varying technologies at different scales based on their distinct geographic and environmental challenges, system designs, technology experience levels, local and state policies, and regulatory incentives. Some utilities opted for full-scale, system-wide implementation, while others tested integration at a pilot scale covering, for example, only a few feeders. Some utilities tested multiple new devices or functions in tandem, which often yielded synergistic benefits not seen by those utilities that tested only a limited set of functions. The maturity of utilities' existing (pre-project) technologies also affected the magnitude of benefits; for instance, utilities that upgraded from manual meter reading to advanced metering infrastructure (AMI) realized more operations and maintenance-based savings than those that began with automated meter reading.

Yet evidence from the 99 SGIG projects shows that smart grid technologies enabled new functions and capabilities that can deliver measurable net benefits to utilities and consumers alike—and deliver economic, environmental, and productivity benefits to society as a whole. Moreover, after the completion of the SGIG program, many grant recipients will continue to invest in smart grid technologies and expand deployments throughout their systems, based on evaluation of the costs and benefits of smart grid options within their unique systems.

DOE analysis of project impacts and benefits revealed a number of key outcomes:

- Synchrophasor deployments improve transmission system visibility and help grid operators prevent large-scale outages
- DA and AMI improve reliability with fewer and shorter outages, faster service restoration, and customer savings

[37] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).
[38] The Edison Foundation Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*, prepared by Adam Cooper (October 2016); The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (September 2009).

- Automated controls for voltage and reactive power management improve efficiency and power factors and reduce energy consumption and costs
- Equipment health sensors prevent equipment failures, reduce outages, and lower operations and maintenance (O&M) costs
- Operational efficiencies from AMI and DA deliver cost savings and improve customer service and satisfaction
- AMI and customer systems improve time-based rate, incentive, and DLC programs that reduce peak demand, power consumption, and bills for many participating customers
- DA and AMI improve integration of DER for grid planning and operations
- SGIG cybersecurity policies improve utility business and technology protection practices to address emerging threats

This section explores how SGIG projects achieved each of these outcomes, citing a selection of key project examples that demonstrate the potential magnitude of smart grid benefits.

2.1 | Synchrophasor Deployments Improve Transmission System Visibility and Help Grid Operators Prevent Large-Scale Outages

The SGIG program deployed phasor measurement units (PMUs) on a massive scale to help detect dangerous disturbances and prevent wide-area blackouts before they happen. PMUs provide game-changing visibility in the transmission system by measuring and delivering data on system conditions 100 times faster than conventional technology, permitting grid operators to identify and rapidly correct for system instabilities, such as frequency oscillations and low voltage, and operate transmission lines at greater capacities.

The SGIG projects marked the first time that many transmission owners and operators installed modern, production-grade PMUs on an operational scale—transitioning synchrophasor technology from a research and off-line analysis tool to one that actively enhances real-time operations. At the start of the SGIG program, the transmission grid had fewer than 166 PMUs, designed for research only; by 2015, there were more than 1,700 networked synchrophasors providing visibility into transmission systems that serve about 88% of total U.S. load.[39] Improved visibility can prevent blackouts such as the 2003 Northeast blackout that cascaded across eight states and two Canadian provinces. Investigators of that blackout concluded that a key contributing factor was grid operators' limited visibility into large-area grid operations, which prevented them from detecting and addressing a relatively minor disruption before it cascaded across regions.[40]

Independent system operators (ISOs) and regional transmission operators (RTOs) also installed or enhanced high-speed communications and data management systems to network the synchrophasors within and across large regions. PMUs enable operators to precisely sample grid conditions at very high speeds over hundreds of miles, with time-stamped data to microsecond accuracy that can be synchronized to provide a precise and comprehensive view of an entire interconnection.

Project utilities developed advanced data transmission and data concentration procedures, providing the necessary quality and trust to use synchrophasor data in engineering, design, and real-time operations to significantly improve

[39] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[40] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (April 2004).

reliability. Synchrophasors have **prevented outages, monitored phase angles to accelerate restoration, detected and diagnosed potentially harmful oscillations, detected and managed islands to support microgrids, and helped operators detect potentially failing equipment**, such as transformers and voltage regulators.

> In 2008, 14 transmission lines taken out of service by Hurricane Gustav formed an electrical island. Entergy's **synchrophasors enabled operators to detect the island and then diagnose and mitigate instabilities within that island, preventing a blackout of New Orleans and Baton Rouge**. This was a motivator for Entergy to triple its number of PMUs to 49 and expand its synchrophasor system capabilities under its SGIG project.[41]

> Using synchrophasor data, the American Transmission Company **identified and replaced a potentially failing transformer, avoiding an extended transmission substation outage**. In a similar manner, The New York Independent System Operator (NYISO) used PMU data to detect a malfunctioning automatic voltage regulator controller in one generating station and a failed power system stabilizer in another.[42]

SGIG recipients also used synchrophasors to correct and validate models of nuclear, hydropower, fossil fuel, and wind generators. **Rapid model validation improved asset utilization and system efficiency, reduced operating costs, and reduced curtailment of renewable energy sources**.

> Western Electricity Coordinating Council (WECC) member Bonneville Power Administration (BPA) **saved as much as $700,000 in avoided power sale losses** and contractor costs by using synchrophasor data to validate and recalibrate its 1,100-megawatt (MW) Columbia nuclear generating station—while the generator remained online.[43]
>
> When a critical 500-kilovolt (kV) tie line between Arizona and California tripped in October 2013, near-real-time **PMU data allowed system operators at WECC to determine that the line could safely be re-energized almost immediately**—avoiding the need to re-dispatch generation and reducing the grid's vulnerability to additional outage contingencies.[44]

Synchrophasor applications have also **largely reduced the time, effort, and costs to analyze system disturbances**, validate system models, and assess the status of the grid.

> The Independent System Operator of New England's (ISO-NE) event analysis applications now automatically collect and analyze synchrophasor data from PMUs all across New England, **enabling engineers to analyze two or three events per week—up from two events per year—using the same resources**.[45]

As PMUs are further networked and data quality improves, PMU data can be integrated into other control systems, allowing operators to receive real-time alerts or even automate system interventions to prevent minor disturbances from cascading into regional outages. The 2011 Southwest blackout, for example, was the result of a cascading failure that took place in seconds—too fast for human intervention. At this time, operators are mainly using PMU data for

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41 DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
42 Ibid.
43 Ibid.
44 Peak Reliability, *Use Synchrophasor Data to Accelerate Reclosing of an Important Tie Line* (March 3, 2014); DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
45 DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

system planning and forensic analysis. Over time, as data and processing capabilities improve, operators can use this technology to manage real-time power flows across wide areas.

2.2 | DA and AMI Improve Reliability with Fewer and Shorter Outages, Faster Service Restoration, and Customer Savings

Power outages following major storms cost the U.S. economy billions of dollars annually. Dependence on a reliable supply of electricity has become a pervasive aspect of modern life. As the nation's critical services and large economic sectors become more digital and automated, power disruptions have potentially greater consequences. By applying advanced communication systems with intelligent devices such as smart meters, digital controls, switches, and sensors, utilities tested advanced outage management approaches that delivered substantial benefits.

Smart meters and AMI enables utilities to remotely pinpoint the location and extent of outages, better direct resources, and equip repair crews with precise, real-time information—often shaving hours or days off restoration time following major storms.

Without AMI, utilities often relied on customer calls to identify outages and sent crews to manually verify restoration during repairs. With AMI, operators can "ping" smart meters to instantly verify their outage status and locate disruptions, reducing truck rolls and allowing utilities to dispatch repairs crews more quickly.

> **PECO restored service an estimated three days faster during a February 2014 storm—even though only 50% of their smart meters were deployed—and automatically restored power to about 37,000 customers** in less than five minutes using automated feeder switching. PECO also avoided 6,000 truck rolls and restored power 2-3 days sooner following Superstorm Sandy in 2012 with its smart meter rollout only 10% complete. [46]

Utilities isolated disruptions and restored downstream customers within seconds by automating distribution tasks such as fault detection and feeder switching.

Automatic feeder switching devices—such as smart switches, automatic reclosers, and remote fault indicators—enabled "self-healing" fault location, isolation, and service restoration (FLISR) capabilities. When a fault occurs or a power line is damaged, these smart technologies work in tandem to detect and clear temporary faults, isolate sustained faults, and automatically re-route power around faults, often within seconds.

> FLISR can reduce outage duration by up to **53%** and reduce the number of affected customers by up to **55%**

For *each* outage event, utilities reduced the number of affected customers by as much as 55% and reduced the duration (total customer minutes of interruption) by up to 53% using FLISR capabilities.[47] Utilities saw the most benefit from FLISR investments that modernized poorly performing or highly vulnerable substations and feeder groups. Savings from avoided switching costs also totaled more than $1.46 million for eight SGIG DA utilities that reported savings from April 2011 to March 2014.[48]

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[46] DOE OE, *Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response* (November 2014).
[47] Results from 15 utilities over a three-year testing period. DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[48] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

Utilities also measured improvements from pre-deployment baselines in SAIFI and SAIDI, the key indices used to measure system reliability. In 2013, three utilities saw a 23-58 percent improvement compared to pre-deployment baselines in SAIFI, the primary metric used to track outage frequency.[49]

> By upgrading its distribution circuits, **PPL Electric Utilities Corporation estimated a 55% drop in the average outage duration (SAIDI) and a 58% decrease in the average number of interruptions (SAIFI)** across its system in 2013. Based on these results, PPL estimates a 25% improvement in reliability over the subsequent five years through continued deployment of distribution automation.[50]

Faster and fewer outages avoided millions of dollars in damages for businesses and customers. Avoided outage costs for industrial, commercial, and residential customers are perhaps the most substantial economic benefit from the SGIG program. Productivity loss, business closures, food spoilage, and other outage costs—particularly for industrial and commercial customers—are often large but are also difficult to accurately estimate. The few utilities that were able to quantify the economic benefits to customers saw substantial savings following major storms.[51]

> **Central Maine Power (CMP) estimates its investments in substation and line reclosers saved customers more than $935,000 in 2014**—and will continue to save a total of $20.7 million through 2020. Customers saved an estimated average of $18,000 per outage involving line reclosers and $29,000 per outage affecting a substation. CMP used DOE's Interruption Cost Estimate (ICE) calculator to estimate the value of an average outage hour (about $97 for 2014-2019) for an average CMP customer.[52]

> **Smart grid technologies reduced utility costs by $1.4 million by restoring power an estimated 1.5 days sooner** following a February 2014 snowstorm at the Electric Power Board (EPB) in Chattanooga, TN. The utility used fault isolation and automated feeder switching to prevent sustained outages to about 70,000 customers, saving about 16 hours of restoration, and used AMI to "ping" smart meters, verify outage status, and redirect repair crews, shaving off another 20 hours of restoration. [53]
>
> Two years earlier during the severe July 2012 derecho, EPB restored power to about 40,000 customers within seconds using automated feeder switching and used AMI data to **restore the system 17 hours sooner, avoiding an estimated $23 million in customer damages** and decreasing the expected outage duration by about half (see Figure 2.1).[54] Reliability improvements from DA investments save EPB's customers $26.8 million annually under normal operations, in addition to the substantial savings during individual severe weather events.

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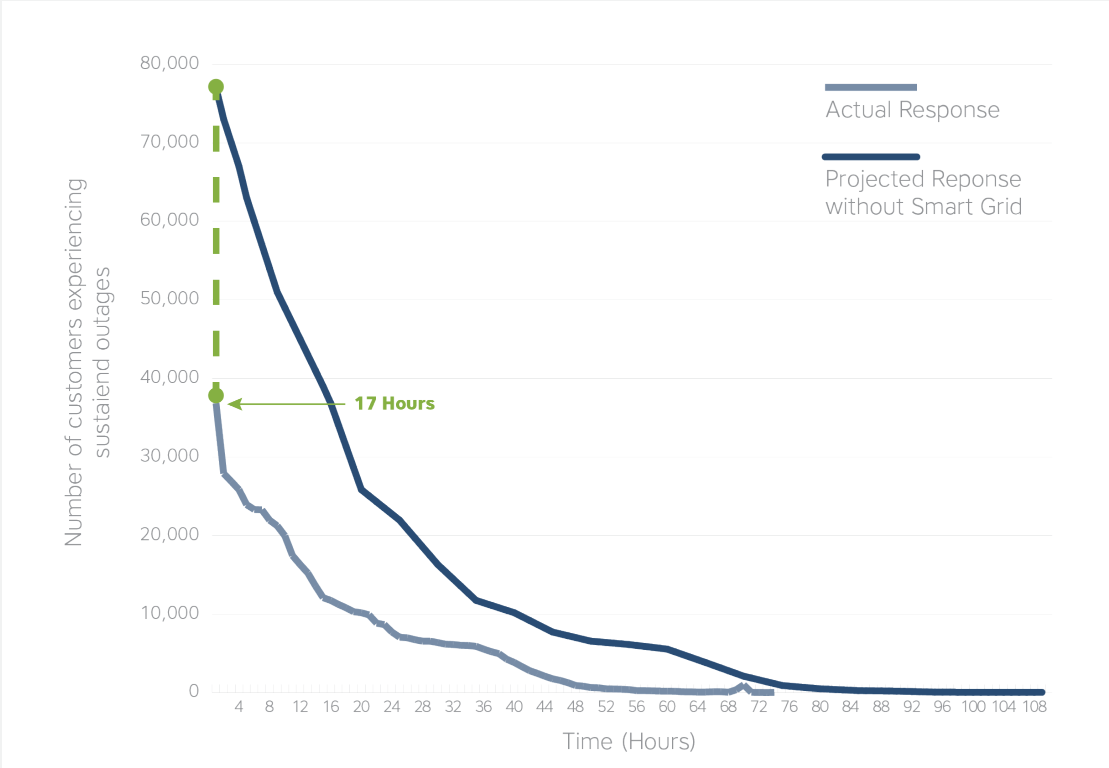
[49] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[50] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[51] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[52] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (September 2016).
[53] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016); DOE OE, *Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response* (October 2014).
[54] DOE and UT-Battelle, *ICE Calculator Case Study Overview: EPB Chattanooga Distribution Automation* (December 2015).

FIGURE 2.1 IMPROVEMENT IN SERVICE RESTORATION BY EPB FOLLOWING A JULY 2012 STORM



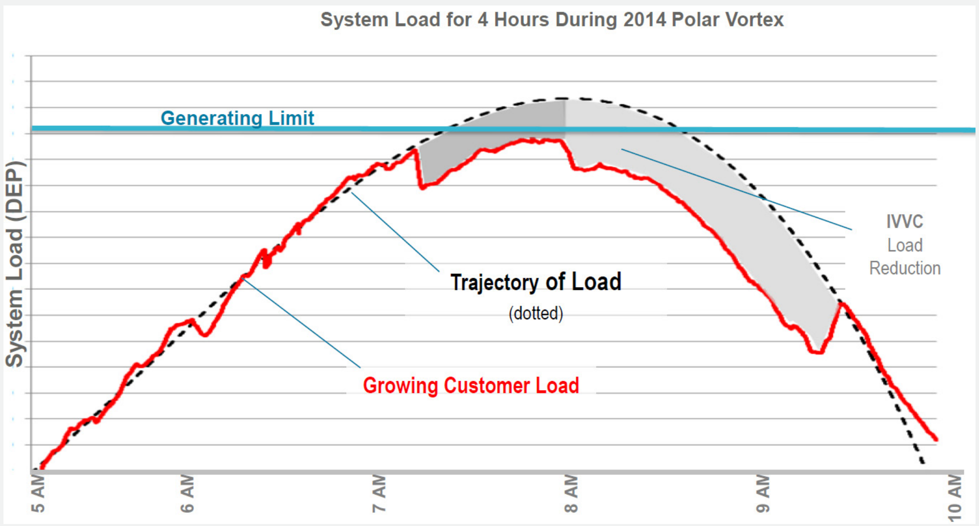
2.3 | Automated Controls for Voltage and Reactive Power Management Improve Efficiency and Power Factors and Reduce Energy Consumption and Costs

Distribution automation applications improve power factors on feeders and deliver lower voltage levels without negative effects on customers or equipment. Utilities can reduce power losses along distribution lines by dynamically optimizing voltage and reactive power levels, which helps to deliver the same amount of power to customers at a lower cost. Conservation voltage reduction (CVR) also reduces customer voltages along a distribution feeder to reduce electricity use, particularly during peak periods. By reducing peak generation, CVR can help utilities avoid fuel costs and defer capital investments in generation assets.

The result is fewer unpredictable outages and higher-quality power—which protects customers' sensitive electronic equipment from damage or limited performance—and improved system efficiencies. SGIG utilities **found that CVR could result in savings of 2–4 percent on affected feeders**—a change that may seem minor, but when applied system-wide, could result in comparable energy savings and hundreds of thousands of dollars in energy costs.

During the morning of January 7, 2014, Duke Energy Progress (DEP; formerly Progress Energy) employed integrated volt/VAR control (IVVC) technology to **avoid a projected outage of roughly 88,000 customers due to a record system load** caused by extreme cold weather from the 2014 polar vortex. As customer load grew in the early morning hours, DEP quickly approached its system generation limit. Using IVVC, DEP met peak load demand by reducing reactive power losses by optimizing the performance of IVVC components such as load tap changers, controls for capacitor banks, and line regulators. The success of voltage reduction efforts to reduce peak load has led Duke to **use IVVC as an alternative to the addition of generation capacity in its service territory**.[55]

FIGURE 2.2 DUKE ENERGY PROGRESS SYSTEM LOAD DURING JANUARY 7, 2014 POLAR VORTEX



Consolidated Edison used its voltage control and reactive power management technologies to **increase its 4kV unit substation capability by 2.8%, resulting in a net savings of $15.7 million**. It also reduced primary losses on its 4 kV systems by 2.3% under peak conditions.[56]

Glendale Water and Power estimates that a five-year CVR project on 65% of feeders can achieve **energy savings of 2%-4% and net power cost savings of $470,000 to $1.2 million per year**.[57]

Continuous voltage optimization formed the largest part of the business case by far for Duke Energy's smart grid deployment plan. It showed a net present value of $155.5 million in a 2011 third-party evaluation by the Public Utilities Commission of Ohio of the estimated revenue and benefit streams from Duke's smart grid operations over 20 years.[58]

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[55] Duke Energy, "Session 2: Conservation and Optimization via Volt/VAR Control," presentation by Jay Oliver at the EPRI-DOE conference "The Smart Grid Experience: Applying Results, Reaching Beyond," Charlotte, North Carolina (October 27–29, 2014).
[56] DOE OE, *Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York* (August 2014).
[57] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[58] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

2.4 | Equipment Health Sensors Prevent Equipment Failures, Reduce Outages, and Lower O&M Costs

By installing intelligent sensors and controls on substation transformers and battery banks, SGIG utilities can also proactively monitor equipment health to predict and prevent costly failures. Newly installed diagnostic systems collect and interpret data from these intelligent devices in the distribution management system, giving operators unprecedented information on system performance in near-real time.

At Florida Power and Light, a newly installed monitor detected a faulty transformer before it failed, preventing an outage that would have affected several thousand customers, and allowing the utility to switch customers to another transformer while replacing the faulty one. FPL tested and replaced the unit, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. [59]

Courtesy of FPL

2.5 | Operational Efficiencies from AMI and DA Deliver Cost Savings and Improve Customer Service and Satisfaction

AMI and customer systems allowed utilities to provide customers with improved service. Rapid, automated, remote meter reading delivered more accurate and timely bills and allowed service connection/disconnection in minutes instead of days. More accurate bills combined with detailed usage information reduced customer complaints and improved customer service call experiences. Improved online bill payments and pre-payment billing plans reduced bill surprises for customers. New smart meter capabilities that enabled utilities to pinpoint and diagnose outages also helped utilities to provide customers with periodic updates and more accurate estimates of service restoration schedules.

Utility O&M improvements from automated meter reading and billing were often substantial. AMI services eliminated time-consuming truck rolls and service appointments, **saving about $316 million in labor and other costs** for 19 utilities over 3 years.[60] **Per-meter O&M cost savings reported by 19 projects averaged $8.37 over a six-month period in 2014.[61]** As expected, utilities with lower customer densities per distribution line-mile observed larger savings per customer served than those with higher customer densities.

Pre-pay billing plans allow near-real-time tracking of energy use to prevent unanticipated costs and reduce service disruptions for customers. For utilities, pre-pay plans help reduce bad debt write-offs; Talquin Electric Cooperative reduced its bad debt write-offs by about 65 percent. Smart meters also provided new capabilities for meter tampering and theft detection, which prevented hundreds of thousands in revenue losses.

[59] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).
[60] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[61] DOE OE, *Distribution Automation: Final Report from the SGIG Program* (2016).

Between 2011 and 2013, Tri-State Electric Membership Corporation (Tri-State) realized a **65% decrease in annual meter operations costs** (from $450,000 to about $156,000 per year) from smart meter deployments. Its pre-pay program and automated connection/disconnection capabilities also contributed to a **50% reduction in unpaid bill write-offs** (from about $52,000 to less than $25,000). Tri-State's payback period is less than five years for its entire smart metering investment.[62]

Central Maine Power's (CMP) system-wide AMI deployment reduced its meter operations costs by more than 80%, with annualized savings of about $6.7 million. Between 2012 and 2013, CMP eliminated almost 121,000 truck rolls—a 97% reduction—and decreased annual vehicle-miles traveled by about 1.4 million. Automated meter reading reduced estimated bills by more than 90%. Service connections can now be completed in less than an hour, rather than the next business day.[63]

2.6 | AMI and Customer Systems Improve Time-Based Rate, Incentive, and DLC Programs that Reduce Peak Demand, Power Consumption, and Bills for Many Participating Customers

Residential electricity consumers have traditionally had few tools with which to manage their consumption and costs. Smart meters and customer-based devices deployed under SGIG allowed customers to take advantage of time-based rates and incentive programs by reducing or shifting their electricity use from peak to off-peak periods—saving them money while reducing peak demand to keep the grid stable and avoid costly peak generation.

Under the SGIG projects, tens of thousands of customers participated for the first time in these new, AMI-enabled rate programs, which included pre-payment plans and time-of-use rates, such as critical peak pricing (CPP), variable peak pricing (VPP), and critical peak rebates (CPR). Load control switches also enabled utilities to temporarily switch off appliances like air conditioners and water heaters during peak periods in exchange for customer savings.

In-home displays (IHDs) and web dashboards provided tens of millions of consumers with better information about their energy usage, while programmable communicating thermostats (PCTs) gave them the control to reduce consumption in response to time-based rates. Web portals and mobile applications often helped customers compare their electricity use with similar users, track consumption and costs, and learn energy-efficiency strategies to reduce consumption and lower bills.

A popular "My Usage" web portal at Tri-State Electric Membership Corporation enabled its many vacation-home owners to remotely monitor usage and even fix faulty appliances after finding anomalies in their usage patterns.

Customers participating in demand-side management programs piloted at 10 utilities that participated in Consumer Behavior Studies **reduced their peak demand by up to 23.5 percent**, **with annual savings for customers ranging from $5 to more than $500**, depending on the type of rates offered.[64] IHDs had limited effect on peak demand reductions

[62] DOE OE, *Smart Meter Investments Benefit Rural Customers in Three Southern States* (March 2014); DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[63] DOE OE, *Smart Meter Investments Yield Positive Results in Maine* (January 2014).
[64] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).

and were rarely cost-effective. However, empowering customers with PCTs often enabled them to achieve higher peak demand reductions of 22–45 percent, compared to reductions of -1–40 percent from customers without PCTs.[65]

The Consumer Behavior Studies evaluated customer acceptance, retention, and reduced usage in response to time-based rates. Results from each two-year study are helping participants identify the most effective rate designs, customer devices, recruitment plans, and outreach and education strategies.

> Oklahoma Gas & Electric (OG&E) averaged **annual savings of $191.78 for residential customers and $570.02 for commercial customers** and reduced load by offering variable peak pricing to about 4,670 participating customers. Based on this success, OG&E expanded the rollout of its time-based rate and PCT program to about 18% (116,000) of its customers, which are achieving 147 MW of peak demand reduction and helping to **defer capital investment in peaking generation**.[66]

2.7 | DA and AMI Improve Integration of DER for Grid Planning and Operations

Smart devices, sensors, and switches deliver their full value *only* when they are connected to a supporting backbone of advanced communications, control, and information systems. Many SGIG utilities installed and upgraded the high-bandwidth communications networks and advanced information and control systems that underpin all smart grid capabilities. For example, many SGIG projects integrated data from new AMI systems with outage management systems (OMS) and geographic information systems (GIS) to equip repair crews with precise outage locations and help prioritize those repairs.

SGIG projects removed one of the key hurdles to wide smart grid deployment by enabling utilities to upgrade these systems and test integration with a small scale of devices. Because advanced communication and control is required to operate even one smart meter or automated control device, these systems and networks represent a fixed cost for all projects, from small pilot studies to full-scale deployments. These systems provide a platform for continued smart grid acceleration over the next decade or more.

With these systems now in place, **SGIG utilities are positioned to deploy more smart grid devices faster and at full scale, and unlock additional capabilities from their smart devices.** Follow-on plans from SGIG utilities demonstrate that many utilities have only scratched the surface of the benefits their investments can provide. Most utilities are immediately building on their SGIG project success by expanding smart grid deployments to other service territories, adopting new technologies they did not test under their SGIG projects, and better networking existing technologies with additional control systems to extract more value from devices deployed under SGIG.

SGIG investments in broadband communications networks and fiber optic systems help transmit large data flows, build capacity for future data-heavy smart grid upgrades, and even automate other utility services (e.g., water and gas metering). Many municipal and public power utilities leveraged advanced communications networks and data management systems from SGIG investments to support comprehensive service upgrades.

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[65] DOE OE, *Advanced Metering Infrastructure and Customer Systems: Final Report from the SGIG Program* (2016).
[66] OG&E, *OG&E Consumer Behavior Study Evaluation Report*, prepared by Farrell, M., Nichols, A., Chiccarelli, K. (August 2012); DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

Burbank Water and Power deployed smart meters to all electric customers and, through a non-SGIG project, to all water customers. The smart electric and water meters use the same communications networks and meter data management systems, lowering costs for the utility and its customers. These systems enable remote meter reading, remote connection and disconnection, outage detection, voltage and power quality monitoring, and tamper detection.

The city-owned Electric Power Board (EPB) of Chattanooga invested $300 million to install more than 6,000 miles of fiber optic cable, providing an advanced communications backbone for city services. Part of that fiber optic network was installed under EPB's SGIG project to support EPB's upgrade of 164 distribution circuits with smart switches, sensors, and controls. The grant allowed EPB to complete its 10-year smart grid deployment plan in less than 3 years. Yet the fiber optic network supported more than just a smart grid—it has attracted new businesses and supported economic development.

Courtesy of EPB

Chattanooga was the first city in the nation to offer ultra-high-speed internet service, up to 200 times faster than the average broadband service, to all 170,000 homeowners and businesses. The broadband network was a key element in Volkswagen's choice of Chattanooga as the site for a billion dollar car factory, according to economic development organization Connected Tennessee. The fiber optic network can provide businesses with a virtual local area network (LAN) to securely connect multiple worksites and send large files and data at speeds of 30 mbps to 1 gigabit per second. [67] The affordable broadband network has attracted small startups and provided critical support to Chattanooga's accelerator GIGTANK, which invited smart grid startups to build and test their applications using millions of anonymous live data points from EPB's smart grid system.[68]

Looking forward, advanced information, communication, and control systems are a primary enabler of grid-scale renewable energy integration and customer-based generation.

Smart metering, advanced distribution automation capabilities, and increased transmission visibility and control all lay the groundwork for utilities to safely and reliably integrate distributed energy resources (DER), including both small-scale and large-scale renewable energy and energy storage.

Synchrophasors in particular now enable operators to monitor the more dynamic state of the power system—caused by variable wind and solar generation in high concentrations—and validate renewable generation models.

The Electric Reliability Council of Texas (ERCOT) demonstrated that **synchrophasor monitoring capabilities can help integrate more wind resources while more effectively managing the impacts of wind power on the grid**. In 2014, ERCOT's synchrophasor system quickly identified a potentially damaging oscillation—undetectable by traditional power system monitoring—caused by a malfunction at a wind farm. The ERCOT operator stopped the oscillation by constraining the unit's output while the malfunction was fixed.[69]

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[67] Connecticut General Assembly Office of Legislative Research, *Chattanooga High Speed Broadband Initiative*, OLR Research Report 2012-R-0515 (December 14, 2012); CBS News, "Fastest Internet service in U.S. found in an unlikely city" (February 28, 2013).
[68] Gig City, "GIGTANK 2014 Program Smart Grid" (February 26, 2014).
[69] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

Idaho Power Company's synchrophasors reduced the time required to validate its wind plant generator model by 75% by delivering data directly to planning engineers and eliminating the need to travel to wind generation sites to collect necessary data. [70]

Increased customer adoption of clean energy and DER, such as rooftop photovoltaic arrays and plug-in electric vehicles, demands that utilities seamlessly manage two-way power flows and data transmission. An advanced metering infrastructure allows customers to participate in electricity markets as "prosumers"—both buying and selling electricity, and participating in demand response programs. SGIG projects installed hundreds of electric vehicle charging stations and tested DER integration at a very small scale, but collected key lessons that will inform future grid integration and market designs.

2.8 | SGIG Cybersecurity Policies Improve Utility Business and Technology Protection Practices to Address Emerging Threats

Smart digital devices added millions of new cyber access points to the grid, making customer privacy and cybersecurity paramount to smart grid success. That is why cybersecurity was an integral part of the SGIG program from its inception. All SGIG recipients were required to create comprehensive cybersecurity plans and build cybersecurity into their policies, technologies, and utility practices. SGIG expert teams augmented these measures with 311 onsite reviews to monitor project progress, including cybersecurity implementation.

Two cybersecurity information exchanges in 2011 and in 2012 promoted peer-to-peer sharing of best practices and lessons learned among SGIG projects. Additional cybersecurity tools and resources were made available through a dedicated website for SGIG project recipients. Through this intensive effort, many SGIG utilities—particularly smaller ones—enhanced cybersecurity practices across their entire system and continue to use the SGIG cybersecurity plan as a model. Improved cybersecurity knowledge will be essential when deploying future smart grid technology and systems. Section 4 describes these activities in greater detail.

A modern grid also relies on interoperability—the ability of networks, systems, and devices to seamlessly connect and share information securely and efficiently. Many various components from different vendors must be interoperable to enable effective, efficient, and cost-efficient system upgrades. In 2009, few interoperability standards or guidelines yet existed. SGIG recipients became active members of the interoperability community, working with DOE and the National Institute of Standards and Technology (NIST) to help identify, develop, and adopt interoperability standards; evaluate deployments; and assess needs. The SGIG program has enabled and supported several key interoperability initiatives:

- A detailed framework and roadmap produced by the National Institute of Standards and Technology[71] and action plans for development produced by the Smart Grid Interoperability Panel.
- A catalog of more than 70 standards deemed capable of meeting interoperability requirements.
- Substantial increases in adoption of industry specifications such as the National Rural Electric Cooperative Association's (NRECA's) "MultiSpeak."
- The Green Button Initiative, which supports access to electricity consumption data from utilities for more than 60 million households and businesses.

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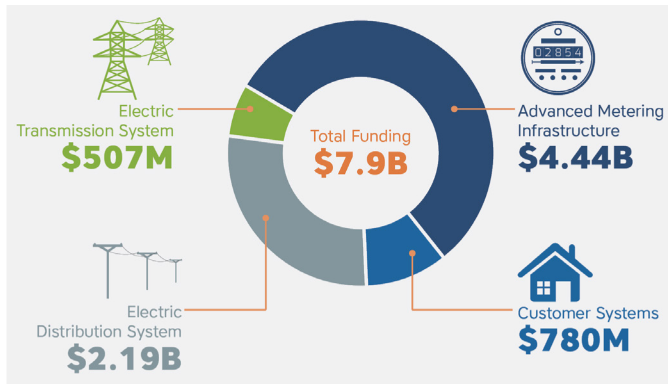
[70] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[71] NIST, *NIST Framework and Roadmap for Smart Grid Interoperability Standards*, Release 3.0, Special Publication 1108r3 (September 2014).

3 | TECHNOLOGY DEPLOYMENT AND APPLICATIONS UNDER SGIG

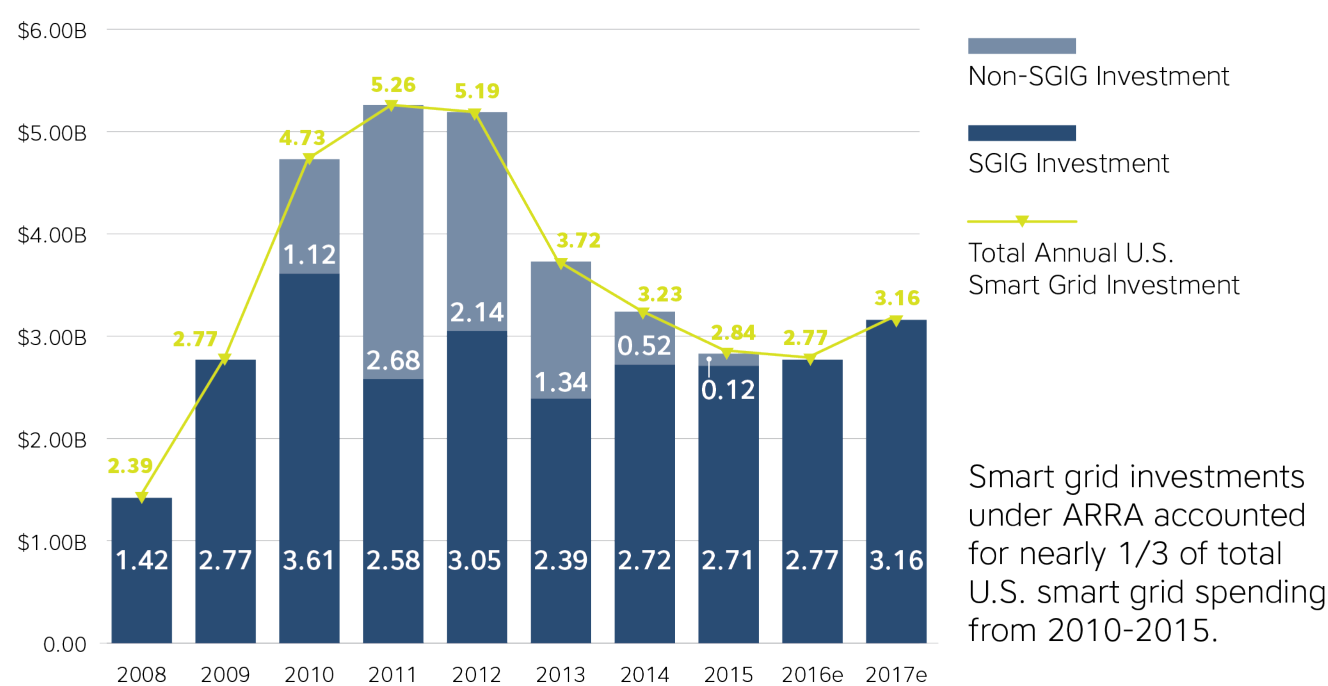
SGIG recipients deployed many smart grid technologies and systems that were in nascent stages of commercial development in 2010, when the first devices were purchased under the program. Careful application of the $7.9 billion total SGIG investment helped speed technology maturation and market deployment during the five-year program. Figure 3.1 shows combined DOE and project spending by types of technologies and systems.

FIGURE 3.1 TOTAL COST-SHARED SGIG EXPENDITURES



In all, the U.S. electricity industry as a whole spent an estimated $24.97 billion for smart grid technology deployed from 2010 through 2015 (excluding transmission system technologies; see Figure 3.2).[72] Smart grid investments under the ARRA accounted for nearly a third of spending during this period. The rate of expenditures was highest in 2010–2012, following the spirit of the ARRA to stimulate the economy. This infusion of technologies is catalyzing continued industry investment over the next several years as smart grid technologies continue to mature.

FIGURE 3.2 U.S. SMART GRID INVESTMENT (BILLIONS), 2008-2017 (ACTUAL AND EXPECTED)



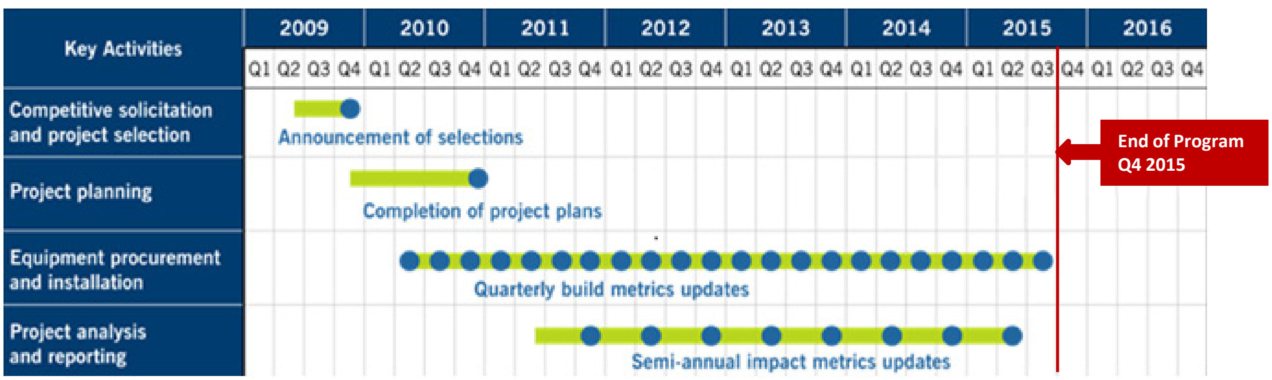
[72] Bloomberg New Energy Finance, *U.S. Smart Grid and Smart Metering Forecasts*, prepared for the U.S. Department of Energy (February 17, 2016).

The DOE Office of Electricity Delivery and Energy Reliability (OE) managed each SGIG project to ensure performance remained on schedule and on budget. The key SGIG program activities followed the schedule shown in Figure 3.3 and remained on target throughout the program.

OE extracted value from the ARRA investment in several key ways:

- **Closely monitored the overall schedule of activities and level of expenditures**, working directly with project recipients to resolve issues.
- **Tracked the deployment of technologies and systems** across all 99 projects using consistent build metrics.
- **Measured technology performance, productivity and cost benefits, and lessons learned** reported by project recipients using a detailed metrics and benefits reporting plan.
- **Published interim results to enable the industry to rapidly learn from and build on SGIG successes**. OE published two SGIG Progress Reports (the first in 2012 and the second in 2013) as well as detailed case studies of project results in key technology areas.
- **Provided technical assistance** to develop and deploy appropriate cybersecurity protections.

FIGURE 3.3 SGIG PROGRAM IMPLEMENTATION SCHEDULE



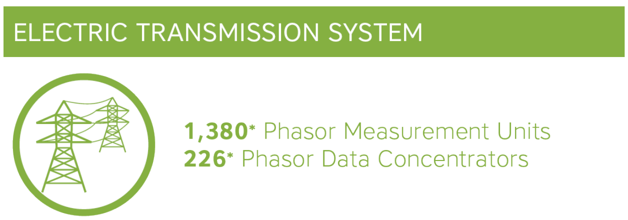
The following sections provide a brief overview of the smart grid technologies and systems deployed under SGIG, and how ARRA investments changed the smart grid technology landscape.

3.1 | Transmission Systems

The ARRA projects resulted in a dramatic expansion in the use of advanced synchrophasor devices and capabilities to improve power system planning and operations—marking the first time transmission owners and operators installed modern, production-grade PMUs and used them in real-time operations, not simply research.

PMUs are devices that take precise grid measurements at high speed, typically 30 observations per second, which is more than 100 times faster than conventional supervisory control and data acquisition (SCADA) technology. Each measurement is stamped with a common time reference and location. PMUs function as synchrophasors when measurements from different locations and utilities are combined and time-aligned (or synchronized), providing operators a precise and comprehensive view of an entire region or interconnection.

FIGURE 3.4. SGIG TRANSMISSION SYSTEM DEPLOYMENT



Transmission system project results under ARRA include 13 SGIG projects and 1 Smart Grid Demonstration Program project.

ARRA grant recipients included independent system operators (ISOs), regional transmission organizations (RTOs), and large and small utilities, participating in 13 SGIG projects and 1 project managed under the Smart Grid Demonstration Program. The SGIG transmission system projects spent approximately $507 million (including both DOE and recipient funds), which represents just 6% of the total SGIG budget. Recipients accelerated synchrophasor technology maturity in three key ways:

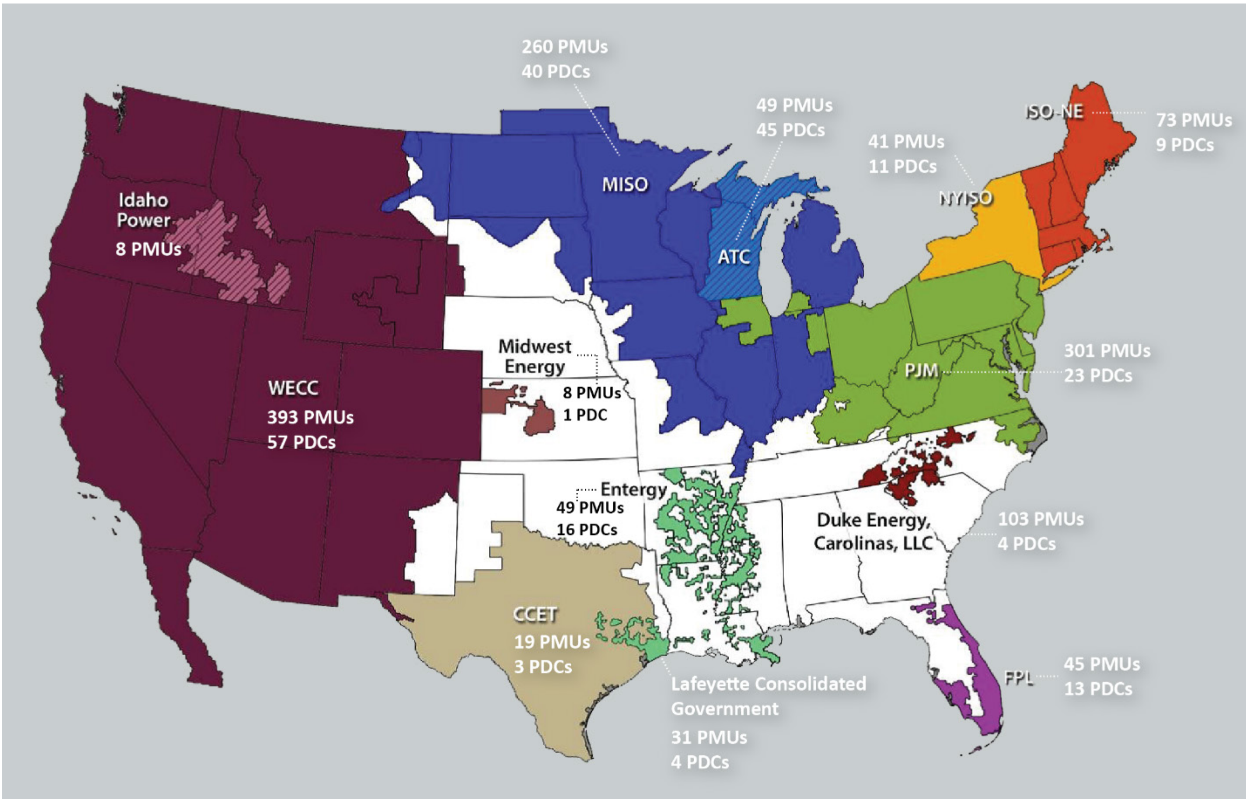
- **Installed 1,380 production-grade PMUs and 226 phasor data concentrators**, which collectively provide operators visibility into the transmission systems that serve approximately 88 percent of the total U.S. load and cover approximately two-thirds of the continental United States.[73] Operators now have near 100 percent visibility of the behavior of the entire U.S. high-voltage transmission network, due in large part to synchrophasor deployments by ARRA projects.[74]
- **Installed or enhanced region-wide, high-speed communications and data management systems** to network synchrophasors, enabling unprecedented data sharing and visibility over large areas. Project utilities developed data transmission and concentration procedures that send PMU data to operators with a 0.019-second latency.
- **Drove significant improvements in data quality by testing data validation, data storage, and advanced applications** needed for real-time aggregation and analysis of synchrophasor data. Utilities trained operators and engineers and improved data quality to the point that they can now use synchrophasor data in system engineering, design, and real-time operations. Project participants developed and implemented rigorous procedures for validating synchrophasor data, monitoring synchrophasor system performance, and restoring service to PMUs to maintain the required data quality.

Recipients also worked closely with the North American Synchrophasor Initiative (NASPI) to coordinate, share information, solve problems, accelerate the development of software applications, and accelerate standards

[73] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).
[74] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

development to enhance the success of the ARRA-funded deployment.[75] PMUs are now in every U.S. interconnection, with expansive new phasor data communications networks.

FIGURE 3.5 SYNCHROPHASOR TECHNOLOGIES INSTALLED UNDER ARRA-FUNDED PROJECTS



Acronyms: FPL – Florida Power & Light; ISO-NE – Independent System Operator of New England; MISO – Midwest ISO; NYISO – New York ISO; WECC – Western Electricity Coordinating Council

3.1.1 | Technology Maturity under SGIG

PMUs were developed in 1988 and first deployed in 1992 with initial funding from DOE, the National Science Foundation, and the Electric Power Research Institute. DOE spent seven years in research and development (R&D) on phasor measurement technology prior to ARRA. By 2009, however, only 200 research-grade PMUs (suitable for research but not grid operational monitoring) were deployed in networks across North America.[76] At the time, problems with PMU data availability and accuracy severely limited industry acceptance of synchrophasor technology.

By 2015, there were more than 1,700 production-grade PMUs deployed across the United States and Canada, streaming data and providing almost 100 percent visibility into the bulk power system (see Figure 3.6).[77] This number includes 166 original (pre-2009) PMUs, the 1,380 PMUs installed with ARRA funding, and over 150 additional PMUs installed by participants or other utilities without federal funding.[78]

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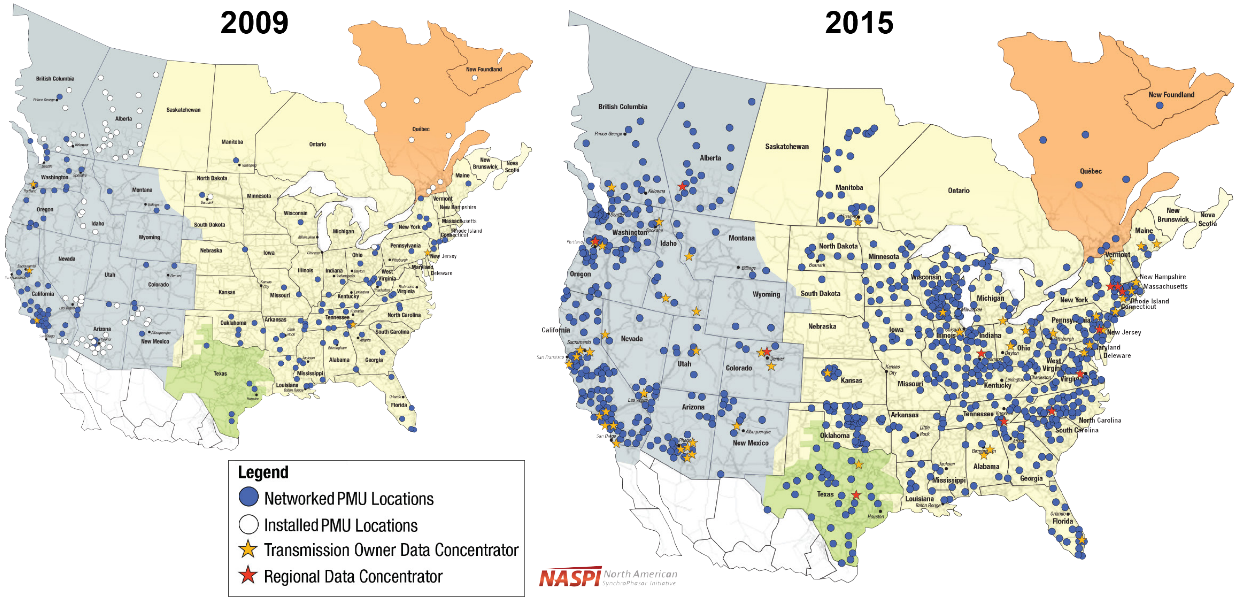
[75] NASPI was collectively created by the electric industry, the North American Electric Reliability Corporation (NERC), and DOE to advance synchrophasor technology development.
[76] North American Phasor Initiative, "Synchrophasor Technology Fact Sheet" (2014).
[77] North American Phasor Initiative, *2014 Survey of Synchrophasor System Networks – Results and Findings* (2015).
[78] DOE OE, *Advancement of Synchrophasor Technology in Projects Funded by the ARRA* (March 2016).

FIGURE 3.6 ADVANCES IN SYNCHROPHASOR DEPLOYMENT ACROSS NORTH AMERICA, 2009-2015



From 2009 to 2015, ARRA-funded projects deployed 1,380 PMUs and 226 PDCs

Maps courtesy of the North American SynchroPhasor Initiative

The ARRA-funded synchrophasor projects transitioned synchrophasor technology from a research and off-line analysis tool to one that informs the real-time operation of the power grid and improves system planning. Synchrophasor applications have reduced grid costs, prevented outages, identified failing and failed equipment, improved models for improved system performance, accelerated restoration after outages, and improved grid operating efficiency.

3.1.2 | Applications Today

Synchrophasors can help maintain power grid reliability, improve system efficiency, increase use of existing assets, and increase organizational efficiency through a wide variety of real-time and study-mode applications (see Table 3.1). The accurate time resolution of synchrophasor measurements allows unprecedented visibility into system conditions, allowing operators to rapidly identify oscillations and voltage instability that cannot be seen using SCADA measurements, and determine operating limits in real time.

Operators can evaluate actual system measurements rather than using mathematical estimates and, thus, are better able to proactively prevent problems before they occur, rather than reacting to an event after the fact. Data from PMUs provide a high-resolution view of localized electrical phenomena. If PMU data are widely shared, conditions that develop across an entire interconnection can be detected and monitored. Wide area situational awareness is the capability for grid operators to see key parameters of the bulk electric power system beyond their service territory–even across an entire interconnection with enough shared data. Wide area displays allow all operators in an interconnection to have a common understanding of the condition of the overall electric grid, resulting in better collaboration and better solutions to emerging problems.

TABLE 3.1 SYNCHROPHASOR CAPABILITIES CREATE TANGIBLE SYSTEM BENEFITS

	Number of Projects	Increased System Reliability	Increased Asset Utilization & Power System Efficiency	Increased Organizational Efficiency
Real-Time Capabilities[79]				
Phase angle monitoring	12	✓	✓	
Oscillation detection and monitoring	11	✓		
Voltage stability monitoring	9	✓		
Event detection, management, & restoration	9	✓		✓
Islanding detection, management, & restoration	4	✓		
Equipment problem detection	9	✓		✓
Wide-area situational awareness	11	✓		✓
Study Mode Capabilities[80]				
Model validation and calibration	11	✓	✓	✓
Post-event analysis	11	✓		✓
Renewable resource integration	3		✓	
Operator training	6	✓		

Synchrophasor data collected during a grid disturbance also enable engineers to compare the system's predicted response (based on engineering models) with actual conditions. Engineering models simulate and explain how individual power plants and large system interconnections perform and interact as a network. Engineers design and operate the grid using these mathematical models. The engineers can then use synchrophasor information to validate and improve the models and model parameters, thus improving power grid operation.

PMUs also allow engineers to validate generator models without having to take the generators off-line. (The standard practice is to schedule a generator outage for model validation every five years.) By avoiding an outage, utilities not only save the cost of scheduling and implementing the outage, but also avoid interruption of service to any consumers.

Additional information about the SGIG synchrophasor projects is available in *Advancement of Synchrophasor Technology in Projects Funded by the ARRA.*

[79] Real-time capabilities are employed in the minute-by-minute operation of the electric power grid. These are generally carried out by power system operators or operational engineers.

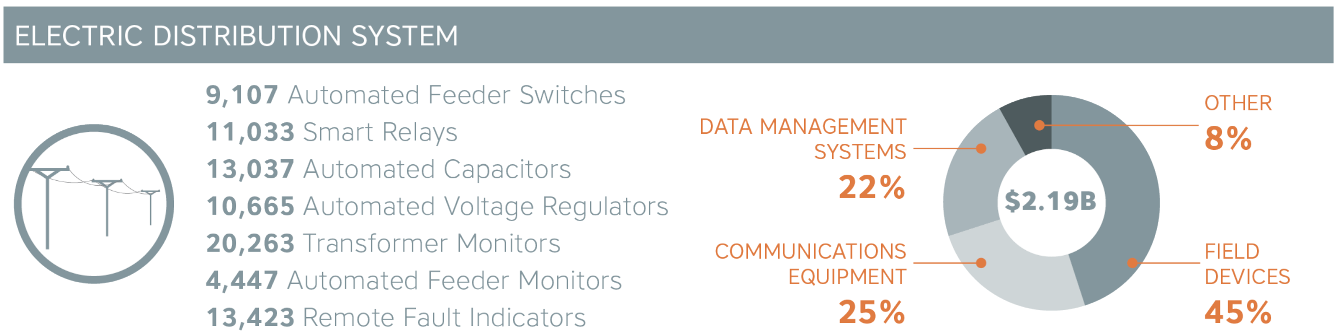
[80] Study mode/planning capabilities, which are generally carried out by power system engineers, are employed in planning for transmission system expansions, generation additions and retirements, system protection, and studying unexpected events or system behaviors.

3.2 | Distribution Systems

SGIG electric distribution system projects installed nearly 82,000 smart digital devices and automated controls on about 6,500 distribution circuits—about 3 percent of the estimated 203,000 distribution circuits in the United States.[81] Though this percentage may seem small, utilities saw significant reliability improvements and cost savings by focusing on the worst-performing feeders first.

Distribution automation (DA) applies advanced control and communication technologies and integrates new digital controls, switches, and sensors to automate electricity delivery tasks that were previously performed using electro-mechanical or manual processes. Digital field devices can work autonomously or be monitored and controlled via communications networks linked to back office systems.

FIGURE 3.7. SGIG DISTRIBUTION SYSTEM DEPLOYMENTS AND INVESTMENT BREAKDOWN



The 62 SGIG electric distribution system projects spent approximately $2.19 billion (including both DOE and recipient funds), which represents about 28 percent of the total SGIG budget. Several projects involved deployments that covered major portions of their service territories, but the majority of projects involved smaller-scale deployments on a limited number of feeders and substations.

Utilities with DA projects not only installed new devices, but also installed or upgraded the communications networks and data management systems that enable advanced applications. Figure 3.7 shows the breakout of investment costs for the SGIG electric distribution projects. Compared to expenditures on communications and data management systems, expenditures on field devices comprise approximately 45 percent of the total. The field devices include automated capacitors, automated switches, relays, regulators, and equipment monitors.

SGIG DA projects tested several new applications for improved outage management, asset utilization, power quality, and equipment health:

- **Automated feeder switching (AFS) and fault location, isolation, and service restoration (FLISR) operations**, which use remote fault indicators, monitors, automated feeder switches, and reclosers in tandem to automate power restoration, reducing both the impact and length of power interruptions. FLISR applications can automatically isolate a fault and rapidly restore service to downstream customers by transferring them to adjacent circuits. By integrating these capabilities with their outage management systems, SGIG utilities helped target repair crews and restore services more quickly.

[81] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

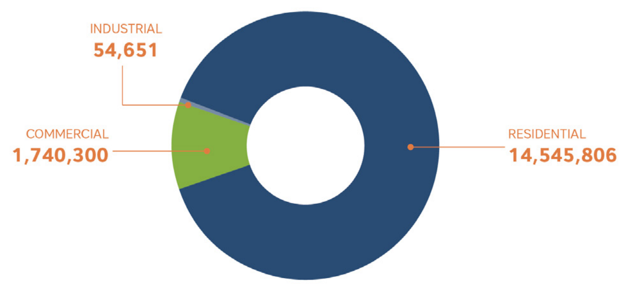
- **Voltage/volt–ampere reactive (volt/VAR control) and conservation voltage reduction (CVR)** using automated capacitors and voltage regulators to improve phase balancing and reactive power compensation and to optimize voltage levels on distribution circuits. These enhanced capabilities can minimize voltage levels and reactive power levels to reduce electricity requirements for real and reactive power during peak periods or for longer periods of time. These capabilities enabled SGIG utilities to maximize existing assets, reduce line losses, and save customers energy.
- **Equipment health monitoring**, using sensors and monitors to identify potentially failing equipment and perform preventative maintenance, and monitor equipment health to extend the life of key assets.

Distribution system modernization is also helping utilities to adapt and accommodate many new requirements, including greater numbers of distributed and renewable resources and demand-side programs and equipment. These include high-efficiency reciprocating engines, wind generators, plug-in electric vehicles, photovoltaic systems, microturbines, fuel cells, and energy storage systems. 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. Several SGIG projects tested electric vehicle charging stations, automated DER dispatch and management, and operation of thermal energy storage at pilot scales, providing results that will help utilities anticipate future operating requirements and plan adaptations. These projects helped those utilities take a large step forward in preparing for high concentrations of new and clean energy resources.

Full discussion of SGIG efforts and successes in deployment of technologies to improve distribution system operations can be found in *Distribution Automation: Final Report from the SGIG Program*.

3.3 | Advanced Metering Infrastructure

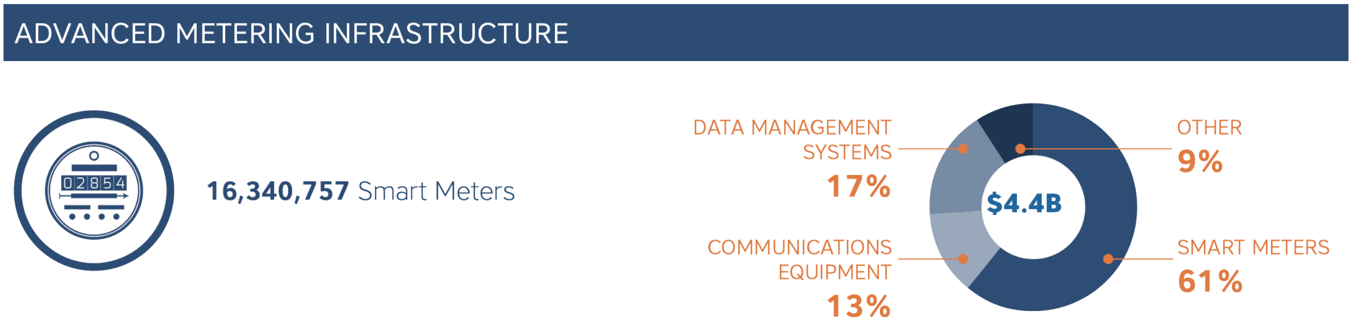
FIGURE 3.8 SGIG SMART METER INSTALLATIONS BY CUSTOMER TYPE



AMI technologies and systems is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. The system provides a number of important functions that were not previously possible or had to be performed manually, such as the ability to automatically and remotely measure electricity use, connect and disconnect service, detect tampering, identify and isolate outages, and monitor voltage. Combined with customer technologies, such as IHDs and PCTs, AMI also enables utilities to offer new time-based rate programs and incentives that encourage customers to reduce peak demand and manage energy consumption and costs.

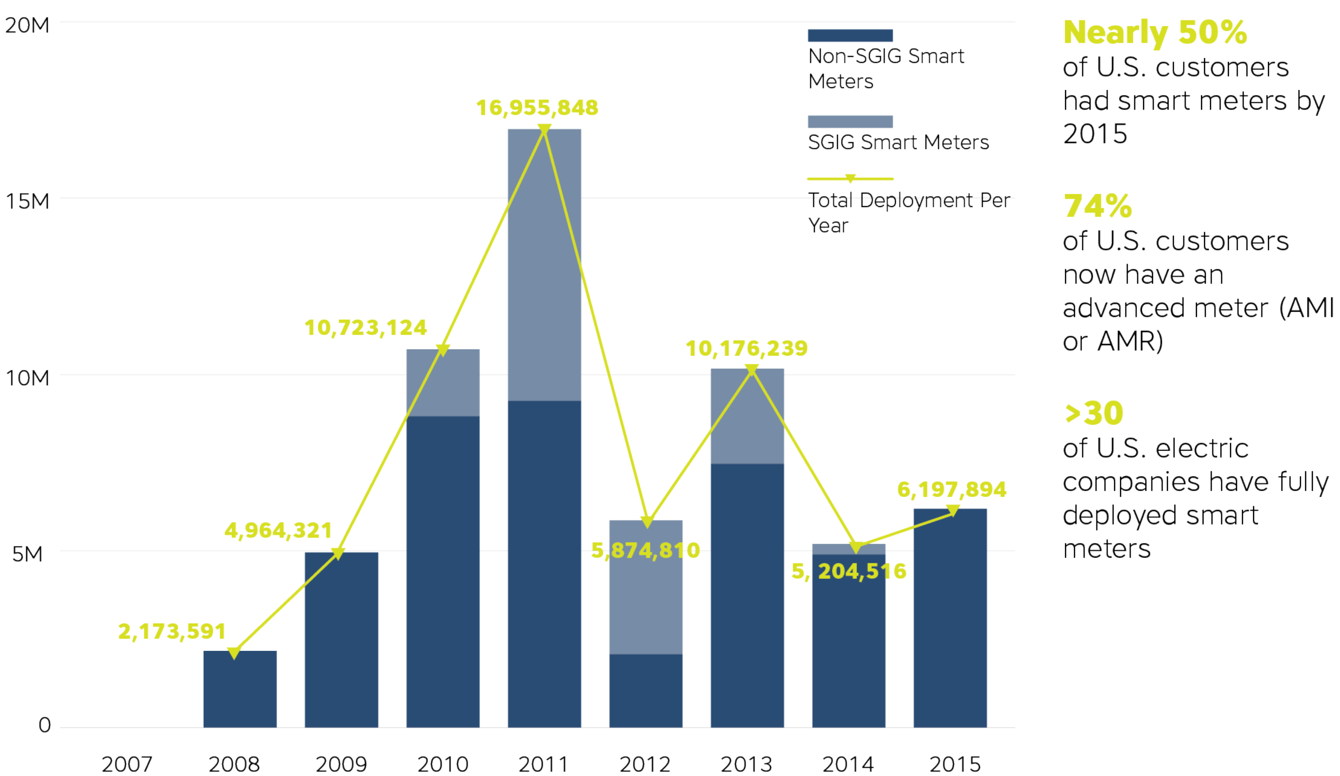
Sixty-four SGIG AMI projects collectively installed more than 16.3 million smart meters, which exceeds the planned level by 5 percent and nearly doubled the number of smart meters installed nationwide before the SGIG program began (Figure 3.8). AMI includes not only the smart meters themselves, but the communications networks, meter data management systems, and other advanced technologies and systems that enable advanced metering capabilities. Figure 3.9 shows the breakdown of SGIG expenditures for smart meters and other AMI technologies and systems. SGIG expenditures totaled about $4.44 billion with about 61 percent for smart meters, 17 percent for meter data management systems, 13 percent for communications equipment, and 9 percent for other expenses.

FIGURE 3.9 SGIG AMI DEPLOYMENTS AND INVESTMENT BREAKDOWN



Smart meters installed under SGIG represent about 33 percent of the 49 million smart meters installed nationwide between 2010 and 2014.[82] The SGIG projects supported rapid industry adoption of smart meter technology and continued, steady implementation is expected based on these successes (Figure 3.10).

FIGURE 3.10 ANNUAL U.S. SMART METER INSTALLATIONS AND SGIG CONTRIBUTIONS



Since its early days, the electric power industry traditionally used electro-mechanical induction meters that measure overall consumption, which must be read manually at regular intervals (mostly monthly) by meter readers, primarily for billing purposes. Traditional meters are incapable of recording consumption levels by time of day and are therefore not usable for time-based rate programs. While AMI systems offer many services, one of the primary applications involves processing meter readings for billing. This eliminates the need for manual meter readings and

[82] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

reduces operating costs. Other applications and services that provide operational benefits include tamper detection, outage detection, and remote service connections and disconnections.

Many of the SGIG AMI projects integrated the outage detection capabilities of the smart meters with outage management and GIS to accelerate response and restoration, and a few of the projects used AMI on a small scale to collect data on voltage and power quality levels, which they coupled with distribution automation technologies and systems for voltage control and reactive power management.

3.4 | Customer Systems

Sixty-six SGIG project recipients also deployed nearly 700,000 technologies and systems to help customers understand their electricity consumption and give them greater control of their use and costs—particularly when combined with new time-based rates. Utilities deployed DLC devices, web portals (through which customers can access usage data), IHDs, and PCTs, along with the communications systems for transmitting data to and from the utilities' AMI systems and back office systems. Usage information allowed customers to take actions to reduce or shift their consumption of electricity from peak to off-peak periods.

Figure 3.11 provides information on customer system project expenditures, showing that expenditures on devices account for 42 percent of the total, which also included web portals, data management systems, and other costs.

FIGURE 3.11 SGIG CUSTOMER SYSTEM DEPLOYMENTS AND INVESTMENT BREAKDOWN (EXCLUDES DER INVESTMENTS)

Industrial and commercial grant recipients also used SGIG funds to develop new systems and devices for energy monitoring and management. These included smart appliances and associated management protocols (Whirlpool), an integrated circuit to enable communication between smart grid-enabled devices and vehicles (Qualcomm-Atheros), automated demand response technology (Honeywell), and two-way communicating load control devices for agricultural customers (M2M).

From the early days of the electric power industry, utilities, policymakers, and academics have discussed the role of customers in the electric power system primarily through offers of time-based rates for electricity.[83] The Public Utility Regulatory Policy Act (PURPA)[84] in 1978 contained the first standards calling for states to consider adoption of time-

[83] Hausman, W. J. and J. L. Neufeld (1984). "Time-of-Day Pricing in the U.S. Electric Power Industry at the Turn of the Century." The Rand Journal of Economics 15(1): 116-126.

[84] Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether it is appropriate to implement time-of-use rates and other ratemaking policies.

based rates. The introduction of electronic meters enabled time-differentiated rates by recording the amount of energy used during on-peak and off-peak hours. During the early 1980s, evaluations of pilot time-of-use (TOU) rate programs during the early 1980s found that customers responded well to TOU rates, but the business case was insufficient to support a wide-scale installation of the required meters.[85] The implementation of smart meters and AMI under SGIG gave utilities the cost-effective capabilities needed to enact time-based rates, while the customer devices gave customers unprecedented capabilities to respond to rate changes and control their electricity costs.

Ten SGIG utilities conducted 11 Consumer Behavior Studies (CBS) to answer key questions facing decision makers on customer acceptance, retention, and demand response in time-based and incentive rate programs. Table 3.2 provides an overview of the scope of the CBS projects. The studies followed rigorous research protocols and applied randomized and controlled experimental design techniques to estimate customer responses more credibly and precisely, providing new information to improve future program designs, implementation strategies, and evaluations. Customers participating in the studies had smart meters and various types of customer systems such as PCTs, IHDs, and web portals; several studies included assessments of customer information and education programs and materials.

TABLE 3.2 SCOPE OF THE CONSUMER BEHAVIOR STUDIES

	CEIC	DTE	GMP	LE	MMLD	MP	NV	OG&E	SMUD	VEC
Rate Treatments										
Critical Peak Pricing		●	●		●	●	●	●	●	
Time-of-Use		●		●		●	●	●	●	
Variable Peak Pricing								●		●
Critical Peak Rebate	●		●							
Non- Rate Treatments										
In-Home Display	●	●	●					●	●	
Programmable Communicating Thermostat	●	●					●	●		
Education							●			
Recruitment Approaches										
Opt-In	●	●	●	●	●	●	●	●	●	●
Opt-Out				●					●	

Utility Abbreviations: First Energy – Cleveland Electric Illuminating Company (CEIC), Detroit Edison (DTE), Green Mountain Power (GMP), Lakeland Electric (LE), Marblehead Municipal Lighting Department (MMLD), Minnesota Power (MP), Nevada Energy (NV), Oklahoma Gas and Electric (OG&E), Sacramento Municipal Utility District (SMUD), Vermont Electric Cooperative (VEC)

The SGIG CBS provided unprecedented analysis of the effects of different rate treatments, opt-in vs. opt-out recruitment approaches, and offering IHDs and PCTs to participating customers.[86]

[85] Faruqui, A. and J. R. Malko (1983). "The residential demand for electricity by time-of-use: A survey of twelve experiments with peak load pricing." Energy 8(10): 781-795.

[86] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

Rate Treatments

Critical peak *pricing* vs. critical peak *rebates*: Retention rates were higher for critical peak rebates (CPR) than for CPP, yet the demand reductions achieved (without a PCT) were generally lower for CPR. However, when PCTs were available as an automated control strategy, the differences in peak demand reductions between CPP and CPR were largely eliminated. This suggests that regardless of the financial incentive, PCTs can be an effective tool to mitigate a customer's loss aversion by allowing them to automate their response to critical peak events.

Effects of TOU: Customers reduced demand during the peak period by 15 percent on average with TOU rates. Responses ranged from a peak demand increase of 1 percent to a peak demand decrease of 29 percent. Customers reduced peak demand more when there was a higher ratio of peak price to off-peak price—by 6 percent on average with a 2:1 price ratio and by 18 percent on average with a price ratio greater than 4:1. Demand reductions were higher when PCTs were available as an automated control strategy, particularly when peak to off-peak price ratios were greater than 2:1. When CPP/CPR rates were overlaid on the TOU rate, average *event* peak demand reduction was 34 percent with PCTs and 24 percent without them.

Recruitment Approaches

Opt-In vs. Opt-Out: Opt-out enrollment rates were 3.5 times higher (93 percent vs. 15 percent) and peak demand reductions were generally lower than voluntary opt-in enrollment, and retention rates were largely the same for both (90 percent vs. 87 percent). While customers in opt-in programs reduced peak demand by up to 50 percent more, the low participation means that opt-out programs can expect larger *aggregate* peak demand reductions than opt-in programs offered to a similar number of customers.

Customer Technologies

Customer *Information* Technologies—IHDs: Offering free IHDs to customers did not have a measured effect on customers' peak demand reductions, and also did not make a substantial difference for enrollment and retention rates (+/- 1-4 percentage points). Because of the cost associated with offering the IHD, utilities saw a lower benefit-cost ratio for rate offerings that included IHDs. In addition, many of the CBS utilities reported significant challenges with this relatively new technology, including low customer connectivity rates and improperly functioning equipment. In one case, the IHD manufacturer decided to halt production and stop support during the study.

Customer *Control* Technologies—PCTs: Though offering customers a free PCT did not make a major difference for retention, peak demand reductions were substantially higher for those that used them. Unlike with IHDs, cost-benefit ratios for PCT offers were favorable—greater than 1.

Expanding Time-Based Rate Programs

More analysis and further studies may be needed to demonstrate to regulators and consumer advocates that these results can be replicated; yet the number of customers participating in time-based and incentive rate programs is on the rise. More than 9 million customers are enrolled in demand-side management programs (including DLC and rate programs), up from 6.7 million in 2009.[87]

[87] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," final yearly data (last release date October 6, 2016).

Three of the 10 CBS utilities allowed participants to continue taking service under the rates after their study was completed. Four of the 10 CBS utilities chose to extend an offer of the rates tested in their study to the broader population of residential customers. For example:

- OG&E has now enrolled approximately 116,000—or about 18 percent—of its total residential customers on its SmartHours program, which includes the offer of a free PCT (taken by 90 percent of participating customers). About 86 percent (100,000) of SmartHours participants are taking service on the variable peak pricing rate tested in its CBS, and are achieving 147 MW of peak demand reduction.
- SMUD chose to make the TOU rate it tested the default for all of its residential customers, starting in 2018. More broadly, the California Public Utility Commission ordered all of the state's investor-owned utilities to make TOU the default for residential customers, citing the very positive results SMUD achieved as grounds for this decision.[88]

[88] DOE OE, *Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies* (September 2016).

4 | CYBERSECURITY AND INTEROPERABILITY IN THE SMART GRID

Smart digital devices added millions of new cyber access points to the grid that could make the system more vulnerable to cyber intrusion if not adequately protected. That is why cybersecurity was a cornerstone of the SGIG program from its onset. The SGIG program aimed to accelerate the development and deployment of effective cybersecurity protections for smart grid technologies and systems using a "cradle-to-grave" approach that ensures cybersecurity protections are "built in" to smart grid technologies and systems from the beginning. This approach offers stronger and longer-lasting protection than security measures that are "bolted on" after systems are fully developed and deployed. DOE worked closely with SGIG projects to ensure that sound cybersecurity policies, plans, and practices were integrated throughout the entire project lifecycle, including design, procurement, installation, commissioning, and ongoing maintenance and support.

Key Cybersecurity Requirements and Resources of the SGIG Program

- **Required that all grant proposals address cybersecurity.** Proposals had 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.
- **Required all 99 SGIG projects to develop and submit Cybersecurity Plans (CSPs).** Prior to starting work, each awardee was required to develop and submit a CSP to DOE 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.
- **Conducted two webinars to guide SGIG grant recipients through the cybersecurity requirements.** The DOE webinars helped guide recipients through the CSP development process and showed how to interpret and integrate new standards and requirements into the CSPs.
- **Formed an expert SGIG cybersecurity team to advise SGIG project teams.** Throughout the duration of the SGIG program, a core team of subject matter experts (SMEs) from national laboratories, universities, and the private sector provided grant recipients with guidance on cybersecurity strategies and system choices. During this period, the team participated in more than 100 conference calls with SGIG grant recipients. The cybersecurity SMEs participated in a total of 311 annual site visits 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 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. The team established criteria used for site visits to determine the cybersecurity posture of each project.
- **Developed a dedicated website of cybersecurity resources specifically for SGIG project recipients**. DOE's secure website served as a central repository of tools, guides, presentations, and resources specifically tailored to the needs of SGIG project teams.
- **Hosted Smart Grid Cybersecurity Information Exchanges in 2011 and 2012**. The Exchanges were essential in promoting peer-to-peer discussions on lessons learned and best practices in developing and implementing cybersecurity for smart grid technologies and systems. Participants also learned about available tools, techniques, and resources for strengthening the security of cyber systems and discussed how to sustain cybersecurity processes once the ARRA projects are completed.

When the SGIG program began in 2009, DOE observed that the sophistication of cybersecurity policies, capabilities, and practices varied greatly among utilities and that few tools existed to help measure, monitor, and track performance of cybersecurity processes and systems.

Across the board, 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 practices. 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.

4.1 | Smart Grid Cybersecurity Tools and Guidelines

A key contributor to the success of SGIG cybersecurity programs was the industry's coordinated development of new cybersecurity guidelines, tools, and procurement language over the last six years. DOE has been working with utilities, vendors, national laboratories, and other partners since 2004 on advanced cybersecurity R&D and to provide cybersecurity tools, expertise, and resources to the energy sector. During the SGIG projects, DOE worked with industry partners and provided ARRA funding to the National Institute of Standards and Technology (NIST) to support the design and implementation of cybersecurity protections and tools, particularly for smart grid applications (see Table 4.1). Cybersecurity tools developed since 2009 include:

- ***Guidelines for Smart Grid Cybersecurity*** ***(NISTIR 7628)***, published by NIST in 2010 using ARRA funds (revision published in 2014.
- ***Guide to Developing a Cybersecurity and Risk Mitigation Plan***, released by NRECA in 2011 as part of a Smart Grid Demonstration Program (SGDP) project (update released in 2014).
- ***Electricity Subsector Cybersecurity Capabilities Maturity Model*** ***(ES-C2M2)***, a voluntary tool, published by DOE in 2012, that helps electric utilities and grid operators to assess their cybersecurity capabilities and prioritize actions and investments to improve cybersecurity.
- ***Cybersecurity Risk Management Process Guideline***, a set of DOE risk management processes developed in 2011 under the Cybersecurity for Energy Delivery Systems program. It enables organizations—regardless of size or organizational or governance structure—to apply effective and efficient risk management processes and tailor them to meet their organizational requirements. It may be used to implement a new cybersecurity program within an organization or to build upon an organization's existing internal cybersecurity policies, standard guidelines, and procedures
- ***Energy Sector Cybersecurity Framework Implementation Guidance***, issued by DOE in 2015 to help the energy sector establish or align existing cybersecurity risk management programs to meet the objectives of the **Framework for Improving Critical Infrastructure Cybersecurity**, released by NIST in 2014.
- ***Cybersecurity Procurement Language for Energy Delivery Systems***, published by DOE and the U.S. Department of Homeland Security in 2009 and revised in 2014, to provide baseline cybersecurity procurement language that asset owners, operators, integrators, and suppliers can use during the procurement process.

TABLE 4.1 CYBERSECURITY PROGRESS FOR SMART GRID SYSTEMS (2009–2015)

STATUS IN 2009	STATUS IN 2015
No common cybersecurity guidelines for smart grid technologies and systems	• NIST *Guidelines for Smart Grid Cybersecurity (NISTIR 7628)* • NRECA *Guide to Developing a Cybersecurity and Risk Mitigation Plan*
Few common tools available to utilities to assess their cybersecurity postures	• DOE *Electricity Subsector Cybersecurity Capabilities Maturity Model (ES-C2M2)* • DOE *Cybersecurity Risk Management Process Guideline* • NIST *Framework for Improving Critical Infrastructure Cybersecurity* and corresponding *Energy Sector Cybersecurity Framework Implementation Guidance*
Lack of common procurement language to assist utilities in embedding cybersecurity in the procurement of energy delivery systems	• *Cybersecurity Procurement Language for Energy Delivery Systems*

4.2 | Smart Grid Interoperability Tools and Guidelines

Interoperability is also essential 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.[89] Many various components from different vendors must be interoperable to enable effective, efficient, and cost-efficient system upgrades.

By 2009, a small number of practitioners identified interoperability as an important issue for smart grid developers to address, yet had only begun to analyze possible options and approaches to standards development. Since 2009, the industry has made substantial progress in tackling key interoperability issues, and the SGIG projects have been important for evaluating deployments, assessing needs, and accomplishing key activities in accelerating interoperability development. Table 4.2 highlights key interoperability accomplishments enabled and supported by the SGIG program.

TABLE 4.2 INTEROPERABILITY PROGRESS FOR SMART GRID SYSTEMS (2009–2015)

STATUS IN 2009	STATUS IN 2015
Introductory and overview materials produced by the GridWise Architecture Council	Detailed framework and roadmap produced by the National Institutes of Standards and Technology and action plans for development produced by the Smart Grid Interoperability Panel
No standards identified as capable of meeting interoperability requirements	Catalog of more than 70 standards deemed capable of meeting interoperability requirements

[89] GridWise Architecture Council, *Introduction to Interoperability and Decision Maker's Interoperability Checklist, v1.0* (April 2007).

STATUS IN 2009	STATUS IN 2015
Few data and tools available to enable or demonstrate the value of interoperability	Substantial increases in adoption of industry specifications such as NRECA's "MultiSpeak"
No common data platforms for aggregating and displaying electricity consumption data for use by consumers	The Green Button Initiative; provides access to electricity consumption data from utilities for more than 60 million households and businesses

With funding under the ARRA, NIST formed the Smart Grid Interoperability Panel (SGIP) in 2009. The Federal Energy Regulatory Commission (FERC) released a Smart Grid Policy Statement that identified four priority functionalities for interoperability: wide-area situational awareness, demand response, electric storage, and electric transportation.

NIST used these priorities to engage a consensus-building process with industry on a smart grid interoperability roadmap. The resulting meetings provided input for the ***NIST Framework and Roadmap for Smart Grid Interoperability Standards***, which identified 75 standards that may be relevant to smart grid interoperability and specified 15 priority action plans to immediately focus work going forward. NIST assembled the SGIP as an industry–government partnership to address these initial actions and to develop new interoperability priorities going forward. NIST maintains the Framework and Roadmap document to reflect the progress made by SGIP and others, as well as new priorities to advance smart grid interoperability. Release 3.0 was published in September 2014.[90]

In 2011, in accordance with Section 1305(d) of the Energy Independence and Security Act of 2007, NIST provided FERC with five initial "families" of smart grid standards to be used for rulemakings. FERC decided not to proceed with rulemakings, indicated further work was needed, and identified the SGIP as the appropriate entity for advancing industry standards for smart grid technologies and systems.

The Green Button Initiative

An important step forward for improving interoperability and customer access to personal energy data is the Green Button Initiative, championed at the federal level by the White House, NIST, and DOE. The Green Button Initiative is an industry-led effort that responded to a White House call to action and is based on a common technical standard developed in collaboration with NIST and SGIP for providing customers with easy access to their electricity usage information. The Initiative is voluntary and aimed, in part, toward enabling software developers and other entrepreneurs to leverage a sufficiently large market to support the creation of innovative applications that can help consumers make the most of their electricity usage information. There are almost 70 organizations participating in the Green Button Initiative, including utilities, manufacturers, and government agencies, many of which have been involved in SGIG projects. Almost 40 other organizations are planning to make commitments. The number of businesses and households served by utilities participating in the Green Button Initiative now exceeds 60 million.

The SGIP has worked with standards development organizations to address priority interoperability issues in 15 completed projects. These collaborations have addressed standards for engaging demand response, energy usage, information models for electric transportation, and specifications for price, product, and energy schedule transactions. The SGIP is conducting projects in areas of substation automation, facility information models, weather

[90] National Institute of Standards and Technology, *Framework and Roadmap for Smart Grid Interoperability Standards*, Release 3.0 (September 2014).

information, microgrids, and financial data for smart grid technology deployment. Recently, the Panel launched an effort for an Open Field Message Bus (OpenFMB) standard to bring information and communications technology promulgated in the open data standards area to the power transmission and distribution automation space.

Based on the standards identified in the NIST Framework and Roadmap documents, the results of priority action efforts, and other standards brought forward by SGIP members, the SGIP developed and maintained a catalog of smart grid interoperability standards (the Catalog). The Catalog is a compendium of standards and practices considered relevant for the development and deployment of a robust, interoperable, and secure smart grid. By the end of 2014, the Catalog had over 70 entries that include reviews on their areas of relevance and cybersecurity aspects.[91]

In December 2012, SGIP evolved from a government project to an independent, privately funded organization with paying members, including many SGIG utilities and solution-provider organizations. This change underscores the commitment of the electric power industry and other smart grid stakeholders to advance interoperability standards. NIST and DOE continue to actively partner with the SGIP to advance smart grid-related activities in which interoperability plays a critical enabling role.

Development of information, tools, and standards for interoperability is an ongoing process and remains one of the keys to successful grid modernization efforts. DOE supports the GridWise Architecture Council (GWAC), a strategic group that promotes the principles of interoperability and integration approaches for deploying smart grid capabilities in the electric system. GWAC's work products have been instrumental in the SGIP and international interoperability efforts.[92]

[91] Smart Grid Interoperability Panel, "Catalog of Standards" (2015).
[92] GridWise Architecture Council, "Publications" (last updated October 2015).

5 | DEPLOYMENT LESSONS LEARNED AND CONCLUSIONS

Smart grid implementation involves the installation of thousands of devices with two-way data communications capabilities supported by high-bandwidth, low-latency communications networks. Together, this equipment forms the basis of a new set of sensing and automation capabilities, supplying grid operators with unprecedented levels of data to process, analyze, store, and turn into actionable information for optimizing grid operations and implementing automated controls.

Information management and control systems such as distribution management systems (DMS), supervisory control and data acquisition systems (SCADA), outage management systems (OMS), meter data management systems (MDMS), customer information systems (CIS), remote monitoring systems (RMS), and geographic information systems (GIS) all need access to these new data streams to accomplish many smart grid functions. 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 and data from smart meters to assess service restoration progress.

As a result, SGIG projects were designed not only to deploy assets, but to enable utilities to uncover integration and operations challenges that can inform future smart grid deployments. SGIG project experiences produced a wealth of information and lessons learned that can be applied by all utilities developing and deploying smart grid systems. These lessons learned cover the gamut of smart grid program implementation, from management and planning, to technology deployment and cybersecurity, to consumer engagement and education. Key lessons learned have been distilled here, and additional lessons learned can be found in the individual project reports on SmartGrid.gov.

5.1 | Smart Grid Project Management and Coordination

Internal collaboration and coordination is essential, as increased coordination is required among partners that previously worked independently. Many smart grid projects cut across functional areas and require well-organized staffing plans and interdepartmental teams to play critical roles. Smart grid deployments often involve changes to business processes, workflow, and logistics. Management of these new system deployments requires coordination of multiple stakeholders across several departments and divisions that used to operate as stand-alone entities. This drives changes to organizational structure and behavior. Many utilities used cross-functional, interdepartmental project implementation teams to plan and monitor deployment activities. Many developed detailed process maps to streamline operating procedures; guide vendors, installers, and service technicians; and provide higher-quality customer services and issues resolution. They also trained staff on both new and old systems and specified integration requirements for vendors bidding on system development projects.

Getting buy-in from senior management and other utility staff members is critical to success. Approvals play an important role in securing appropriate levels of funding and labor resources. The utilities found that this generally involved ongoing activities and regular updates and was not accomplished all at once at the outset of projects.

Smart grid implementation often results in new ways of doing business and engaging with customers. Many of the SGIG projects made organizational changes in metering, customer service, marketing, and distribution operations, particularly in areas that require enhanced levels of integration of both new information systems and job functions. In many instances, these changes involved workforce training programs to develop new skillsets in areas such as database management, data analytics and visualization, interoperability, and cybersecurity.

Installing a synchrophasor system across an interconnection requires significant interaction among stakeholders. Operators must be engaged early to ensure that all components of the system perform their functions properly and interoperate to form a complete wide-area monitoring system. Common language and naming standards are needed. Project teams should schedule adequate time for partnership agreements.

5.2 | Workforce Training and Expertise Development

Education and training programs for headquarters and field staff about the requirements of the new devices and systems are essential. The utilities found implementation of FLISR systems resulted in significant process changes that require greater expertise in information systems, database management, and grid analytics. AMI and DA implementation often required learning new tools and techniques for smart meter data analytics and visualization, particularly in new areas such as electricity theft detection, and for outage detection and notification and voltage-level monitoring. To increase acceptance and capitalize on synchrophasor investments, operators and engineers must be sufficiently engaged, trained, and committed to working with new synchrophasor data and potential applications. Significant engagement is needed to build awareness of the value synchrophasors can provide to their mission.

Use of cross-functional teams helped several of the utilities to find multi-disciplinary solutions. Technical teams of software and hardware engineers, data analysts, and business process specialists were typically required for success. Several utilities found field staff required the most time and attention to learn new equipment capabilities and gain confidence in its proper operations.

5.3 | Evaluating Communication System Requirements

Communications networks are foundational investments, and there is great value in designing communications systems upgrades that meet the bandwidth, latency, and capacity requirements to serve multiple existing and future smart grid applications. One of the core technologies for synchrophasors, DA, and AMI are communications networks that are capable of processing large volumes of data and accomplishing automated controls. By attempting to realize synergies in communications strategies, some projects can leverage resources and minimize training requirements, vendor interactions, information technology interfaces, software solutions, and systems integration requirements. 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 would benefit from comprehensive evaluations for communications requirements from the start of project planning that also considers future applications. Less-than-robust radio communications can interfere with distribution automation operations. The two-way communications network must have sufficient coverage and capacity to interface and interoperate with a wide variety of technologies and systems, including various field devices and DMS, OMS, and SCADA systems. Most of the utilities chose to process meter readings at least every 60 minutes for every customer, stretching the limits of existing corporate communications networks and data management capabilities.

High-bandwidth communications networks can not only enable a smart grid, but also support smart cities. Several public power utilities have adopted long-term, comprehensive approaches to smart grid planning that include building communications networks with the capacity to integrate future smart grid applications *and* to provide city services other than electricity, such as metering for gas and water or high-speed internet access to promote business development. These investments lay the groundwork for smart applications in other sectors and allow the city to extract more value out of investments in communications infrastructure.

Designing and maintaining a low-latency communications system adequate for synchrophasor data delivery presented challenges. The high bandwidth, high frequency, and sheer volume of PMU data create special requirements when implementing analytics, visualization, and information storage and retrieval. Data delivery requires careful design, particularly because the communications infrastructure for data used in operational applications must be as resilient as the power delivery infrastructure.

5.4 | Data Storage, Analysis, and Visualization

Smart grid technologies produce large volumes of data that require additional processing capabilities. Data processing, warehousing, analysis, and visualization tools were needed, and these required significant resources and planning to develop. Tools, visualization techniques, and dashboards that can summarize the data and turn it into actionable information for grid operators are paramount and need to be considered in in the implementation process.

Build data management requirements into system designs from the start. Make use of data warehouses (for enterprise data) and data historians (for operation data) and establish policies for data storage, retention, access, and security. 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.

5.5 | Systems Integration

Integration of new and legacy systems such as SCADA was a consistent challenge for virtually all of the 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.

Turn-key solutions were not generally available for the SGIG utilities. 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.

Interoperability among technologies and systems is paramount, and often requires extra testing, coding, and systems development. Avoid investing in equipment that cannot interface easily with other devices, or requires excessive amounts of customized solutions. Conducting simulation modeling and system and equipment testing proved essential in reducing deployment errors, because testing validated interoperability and network connections. Smart grid deployments require additional steps and considerations that do not necessarily follow traditional utility asset management practices.

AMI became an essential aspect of service restoration activities and OMS operations for the many SGIG projects that implemented both DA and AMI. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to the precise locations where they are needed. Some utilities used GIS to create detailed outage maps, and some of these cases were posted on utility websites to keep the public and local media informed with service restoration progress.

In many cases, solutions for integrating meter data with other systems and functions required additional development to provide software fixes after the fact, which often resulted in unexpected costs and schedule delays. The majority of projects reported that this was one of the most important lessons learned about investments in AMI and customer systems.

Not all utilities are in a position to take on the challenges and integrate AMI with OMS, DMS, SCADA, GIS, and other distribution operations systems. While last-gasp alerts and meter pinging capabilities are available for all smart meter deployments, there are systems integration issues to tackle in making full use of them. **Utilities facing regular and severe weather events, and storm-induced outages, have greater incentives for using AMI for outage management than those that do not.** Several of the SGIG projects implemented major recovery operations following Hurricane Irene in 2011 and Superstorm Sandy in 2012. SGIG projects in the Mid-Atlantic and Northeastern states reported using AMI to support restoration efforts following these devastating storms.

Integrating a large number and variety of devices such as PMUs, PDCs, precise time clocks, and communications system components into a cohesive system is a challenging task. This task is further compounded when using equipment and protocols that do not meet accepted standards. Off-the-shelf hardware and standard communications protocols should be used whenever possible to improve system integration capability and reduce cost.

5.6 | Equipment and Software Testing and Modeling

Plan for both laboratory and field tests of all DA technologies and systems. Simulations did not catch all of the problems experienced during field operations. Extensive operational experience is also often needed before wider system deployment of new technologies and capabilities. For example, automatic switching reconfigures circuit boundaries, which can complicate the coordination of field crews during major storms. As a result, some utilities disable FLISR operations during storm events. The utilities believe this is an indicator of the need for them to gain further experience before expanding deployments.

Project plans must allow for technology evolution as well as changes in standards and regulatory requirements. For some projects, lack of technology maturity of equipment and software required continuous testing, improvements, and software updates. It was helpful to build testing and refinement periods into project schedules.

Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment. Standard templates from vendors typically require customization to meet each utility's unique distribution system configurations and integrate effectively with existing SCADA systems, OMS, and DMS. As a result, more frequent field tests and evaluations were often required.

PMUs and associated intelligent components evolve at much faster rates than more traditional transmission equipment and should be planned for accordingly. PMU applications should be scalable and adaptable as the technology becomes more widespread.

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

5.7 | Cybersecurity

Make cybersecurity part of the company culture. A good cybersecurity plan can drive best practices and sharing of lessons learned, help to allocate resources, help to streamline regulatory structure, and create a common vocabulary to facilitate dialogue. A company should detail roles, responsibilities, and authorities of each party and maintain an organizational chain of accountability to senior management. Making the plan a living document can adapt to changing project needs and the ever-evolving threat environment.

Obtain management support. Support for cybersecurity must come from the top to ensure the cybersecurity program's success. Management support must be gained upfront and executives kept informed throughout the project. Business benefits must be explained to executives at each stage to inform their decision making.

Plan carefully. Developing cybersecurity-specific procurement contract language when procuring systems, products, and related services can prevent multiple potential issues from arising. Establishing a secure, compliant, trusted communication channel early facilitates the exchange of sensitive information. To the extent possible, systems must have upgrade capability to meet future requirements but should also strive for simplicity. Cybersecurity should not be addressed in a vacuum but rather needs to complement the major goal (i.e., maintaining a safe and reliable electric grid).

Strive to stay ahead of the trends. The cybersecurity program should be designed to support emerging smart grid cybersecurity standards. Consideration should be given to interoperability as well as device security. Utilities can learn from their peers' experiences in trends in technologies and their implementation. Becoming active in national groups to share information can help utilities stay abreast of new developments.

Actively engage and inform the customer. Communication with the customer must be a priority (e.g., contract, bill of rights, security communication, benefits to customers). Communications should specify what information is being collected and why to alleviate customer concerns. Utilities must correct misinformation and provide accurate privacy information to consumers. Utilities should undertake educational campaigns and make effective communication with customers an ongoing responsibility.

Learn from other utility cybersecurity deployments. Utilities can benefit from sharing their lessons on assessing, identifying, and mitigating risks at each stage of the development lifecycle. Taking the time for lessons learned during the pilot phase prior to full production and rollout can help ease transition to the implementation phase. Adherence to relevant cybersecurity standards and/or best practices provides a smoother implementation path.

5.8 | Consumer Engagement and Education

Several utilities found devices such as PCTs effective in assisting customers and utilities to achieve reliable peak demand reductions. IHDs were less helpful, and in many cases, participating customers declined to use them. Technical issues with their operations, including interoperability problems with smart meters, affected IHD effectiveness. At least one IHD manufacturer decided to stop making and supporting their product midway through the SGIG program. This decision reflects the relative immaturity of the market for customer systems, and many vendors are in the process of developing new tools for customers that involve mobile phones and computers for conveying smart meter data about consumption and costs.

Conducting outreach and education for customers was valuable to encourage their involvement in web portal feedback programs and tools, and to raise awareness about smart meter deployments and counter misinformation about health effects and data privacy. Outreach efforts typically began early in the project and included educational programs with video and mailing components. Customer service representatives received focused training to effectively address customer questions and concerns. Public meetings with community groups increased the understanding of the utilities about customer needs and concerns, and enabled informative dialogs and discussions.

Utilities that tested electric vehicle charging stations found it valuable to educate not only customers but also auto dealerships, vendors, host sites, local officials, installation contractors, and others on the program and technology prior to implementation. Many initially installed a small number of chargers as demonstrations, and evaluated their use to justify larger deployments. They considered the needs of the different target markets—such as single families, multi-family housing units, fleets, employers, dealerships, and public access—and evaluated use cases for each that examine the charging patterns of those users.

6 | FUTURE DIRECTIONS AND NEXT STEPS

The SGIG program accelerated grid modernization at a critical time and demonstrated that smart grid technologies can deliver substantial benefits and cost savings to utilities and consumers alike. Yet the United States is still on the cusp of a significant transformation in the way electricity is made, sold, delivered, and stored. As the cost of customer-based and distributed generation decreases and the energy mix changes, fully modernizing the nation's entire electric transmission and distribution grid will become an even greater priority, requiring substantial additional stakeholder investment and commitment. The Electric Power Research Institute (EPRI) and others estimate this will require $338–$476 billion of new investment (in addition to investments for reliability and replacement) through 2030.[93] DOE's 2015 *Quadrennial Energy Review* (QER) recognized that continued investments in energy efficiency and smart grid technologies contribute to enhanced resilience, reduced pollution, and operational flexibility for utilities and customers over the years to come.[94]

This chapter examines how SGIG utilities plan to continue implementing smart grid over the next several years, and the next frontier of technology challenges and priorities for the industry as a whole for grid modernization in the decades to come.

6.1 | Expected Follow-On Investments for SGIG Utilities

While the combined industry and government investment of $7.9 billion was substantial, these investments represent a relatively small portion of the total level of investment that the electric power industry is expected to contribute towards grid modernization over the next several decades. For many participating utilities, the SGIG projects accelerated the early stages of larger, long-term strategies for smart grid investment.

In fact, most SGIG projects were explicitly designed to *jumpstart* grid modernization by enabling many utilities to conduct integration tests and explore smart grid technology costs and performance on a limited portion of their systems. The majority of SGIG utilities testing distribution automation capabilities deployed technologies and systems that covered 20 percent or less of their service territories. While just over half of the utilities deploying AMI had full-scale deployments, the remainder tested AMI at pilot or partial scales.

Based on the scale of their SGIG projects and their project successes, many utilities are planning to follow their SGIG projects with investments to either 1) **expand technology deployments** to more customers and greater service territories, or 2) **leverage untapped capabilities in their existing smart grid technologies** by further integrating installed smart grid technologies with communications, data management, and control systems.

AMI

Many utilities that participated in AMI projects plan to expand smart meter deployments system-wide. Several public power utilities are planning to expand smart metering to cover their other services like water and gas metering. With ongoing water shortages in California, utilities there are moving toward using smart meters to track water consumption.

[93] Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid* (2011).
[94] DOE, *Quadrennial Energy Review: First Installment*, Chapter III: Modernizing the Electric Grid (April 2015).

Distribution

Most utilities only partially deployed distribution automation, and now plan to use project results to prioritize modernization of additional substations and feeders. Many utilities are upgrading the worst performing substations and feeders first, or those feeders serving critical customers with high reliability requirements. Several SGIG utilities are also planning to add DA capabilities to existing deployments by upgrading communications capacity, enabling them to use DA functions embedded in existing devices and management systems.

A few SGIG projects explored using communications and controls for demand-side technologies beyond residences, such as ice storage systems for commercial buildings, load control devices for agricultural irrigation pumps, and demand management software for commercial and industrial energy management systems. DOE expects more utilities, developers, and vendors to expand the use of SGIG-enabled communications platforms to accomplish demand management objectives beyond the residential sector.

Based on the results of their projects, several SGIG utilities plan to implement centralized DMS with models of grid operations that are updated continuously based on changes in grid conditions. Other utilities are moving toward more decentralized outage management and equipment maintenance. These organizations plan to build on SGIG investments in information systems to equip field crews with more data and information for conducting maintenance, repair, and service restoration activities. Some of the SGIG municipal utilities are leveraging investments in high-bandwidth, low-latency communications.

Transmission

In the transmission system, several SGIG utilities plan to increase the density of PMUs to achieve full system coverage, further expand high-bandwidth communication systems to support PMU data transfer and management, and invest in new data management, visualization, and analysis systems.

Transmission system operators will also continue to integrate synchrophasor data into planning and operating decisions and leverage unused capabilities to extract more value from the technology. At this time, 11 of the 13 participants are using PMU data to inform power systems planning, and 12 are using the data to inform power systems operations. Most participants can expand their applications of synchrophasor technologies as they continue to build familiarity and incorporate new procedures—an elaborate and time consuming process that involves thoroughly validating the procedure over time to account for seasonal changes of systems conditions. Currently, 5 of the ARRA participants have formally implemented new procedures.

Customer Systems

AMI utilities are also planning to implement new TOU rates to encourage customers to shift consumption to off-peak periods. Several of the SGIG CBS utilities are evaluating the results of their studies to inform decisions about wider implementation of dynamic pricing programs.

6.2 | Smart Grid Technology Development Challenges

Achieving the promise of the work begun by the SGIG program demands ongoing initiatives to replace aging grid assets; develop and deploy advanced technologies, tools, and techniques; and examine technology, policy, market, and institutional barriers to private sector investments and next-generation grid operation. DOE's 2015 *Quadrennial Technology Review* cited several significant economic, environmental, security, and competitiveness challenges relative to energy systems today. Lessons learned from SGIG align with the QTR's analysis of the challenges and technology needs for continued smart grid advancement. Several factors will shape the future of grid modernization:

Vast amounts of new data will require a new class of monitoring, control, and analytic capabilities to unlock the full value of smart grid technologies. Smart meters, PMUs, and other devices deliver extremely timely and granular data at large volumes that will require utilities to invest in high-bandwidth communications networks and advanced data analytics to transform data points into information that can be used to better automate controls and inform operator decisions. This advanced monitoring and control will be paramount to integrate large amounts of variable generation and reduce susceptibility of the system to destabilizing events. Specific technology needs include:

- **New data management, visualization, and analysis tools are needed that can use large volumes of data from PMUs in the transmission system and other smart sensors in the distribution system.** As measurement technologies improve, the analytical processing time also needs to be reduced—from tens of seconds to subseconds—to move from monitoring and visualization to automated controls. For example, the use of PMU data for automated, coordinated, system-level control remains an area of research rather than practice. System flexibility will increase as transmission operators have a wider array of sources to keep the system in balance, including spinning reserves, existing generator ramping capability, power flows between balancing areas, demand response, energy storage, and distributed energy resources. Leveraging these resources requires adequate sensors, coupled with sufficient data analysis and visualization to enable rapid operator decision-making or automated response.
- **Coupling high-resolution data streams with computational advances will enable faster, predictive capabilities as the distribution system becomes more complex, with more points of control, and load becomes less predictable.** Advanced software and models are needed to provide robust "real-time" monitoring and detection, help operators interpret and visualize data, predict conditions, and enable faster operator or automated control and mitigation to ensure reliability and safety. Synchrophasor technologies in particular provide high-speed granular data, offering benefits that are still currently constrained by the operator's ability to visualizer, interpret, and respond to the events—typically on the order of tens of seconds or minutes.
- **Fast, high-resolution, low-cost sensors for the distribution system—such as micro-synchrophasors or distribution synchrophasors—will be needed to ensure reliability and power quality as more distributed energy resources are deployed.** Currently, most distribution system operators have limited visibility into the conditions and state of the system, with the exception of distribution substation assets. Visibility deep into the system (e.g., along feeders to utility meters and possibly into buildings) is needed to enable advanced applications.
- **Further advancement is needed in the control systems, algorithms, and grid models that utilize new data streams.** More rapid and precise control of the electric power system is needed to manage the changing generation mix. Emerging control systems must coordinate and manage distributed resources across the entire system, from load to balancing area. Broad coordination adds complexity, and expands the number of control actions to be considered. High-fidelity models, tools, and simulators that are user-friendly and accessible to decision makers will also be needed, including a common framework for modeling and co-simulation of tools from disparate technical domains (e.g., power flow, communications, and markets).
- **Resilient and adaptive control systems with secure, low-latency communications networks will be needed to maintain strong physical and cyber security of the grid.** Reliable electricity operations will increasingly require high-speed data transfer with precise timing, and therefore may not tolerate the latency that might

be injected by encryption or other security measures. Increased use of distributed energy resources and smart controls in end-use devices requires new levels of data communication and coordination deployed down through the distribution system and to the end user.

Regulators and utilities must be ready as new utility business models, system architectures, and planning requirements emerge from increased grid modernization and DER integration. Large saturation of DERs in certain areas will require new approaches to long-term utility planning, regulation, and markets that can maintain reliability while involving consumers and third-parties in electricity management and generation. Policy decisions on renewable energy and DER adoption will need to consider the impact on grid operations and ensure grid modernization efforts can keep pace. As distributed generation and customer market participation proliferate, these trends may create new technical requirements for the power grid and redefine its fundamental design and operational structures. Energy storage may help to balance supply and demand and better integrate a changing generation mix, but will require a control architecture that optimally integrates storage as a resource. Critical changes are needed in the structure of controls systems, coordination frameworks, communications, and overall industry structure. It is imperative that changes to these deeply interconnected systems, models, and architectures are managed in coordination.

DOE can continue to support grid modernization by using its convening powers to support industry information sharing; continue supporting research, development, and demonstration efforts; encourage cybersecurity and interoperability standards work; and support universities, consultants, and electric industry members that are developing and enhancing devices, models, and applications. By continuing to act as an engine to drive innovation, technology development, and adoption, DOE can ensure technical hurdles are overcome. Likewise, as a cross-industry mediator and government-wide leader, DOE can also help address key policy and regulatory barriers.

6.3 | Next Steps

With the energy landscape in the United States undergoing fundamental and historic change, DOE continues to see a secure, resilient, and reliable U.S. electric grid as a critical component of our nation's infrastructure. The SGIG program has helped to lay significant groundwork toward nationwide modernization. The program's legacy includes not only wide-scale deployment but a wealth of experience in smart grid technology: information for decision makers, lessons learned by deploying utilities, more mature products, and a more experienced vendor community.

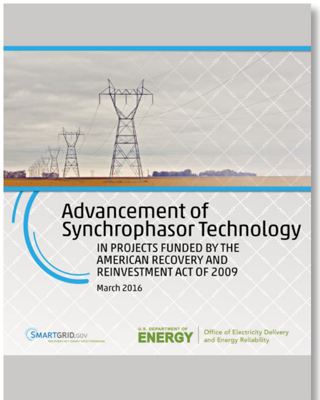
DOE has already begun to build on these successes. In January 2016, the Department announced a comprehensive new Grid Modernization Multi-Year Program Plan to follow through on the needs and opportunities identified in the first installment of the QER, released in April 2015.[95] A blueprint for modernizing the grid, the new program will invest up to $220 million in 80 grid modernization projects at the National Laboratories supporting critical R&D in advanced storage systems, clean energy integration, standards and test procedures, and other key grid modernization areas.[96]

While the first installment of the QER examined North American energy transmission, storage, and distribution infrastructure, the second installment will examine the electric system from generation to end use, including a more comprehensive look at smart grid components.[97] These and other efforts will continue DOE's commitment to a modern, secure and reliable electricity system for the 21st century.

[95] DOE, *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure* (April 2015).
[96] DOE, "DOE Announces $220 Million in Grid Modernization Funding" (January 14, 2016).
[97] DOE, "QER 1.2: An Integrated Study of the U.S. Electricity System," Stakeholder Briefing Memo (February 4, 2016).

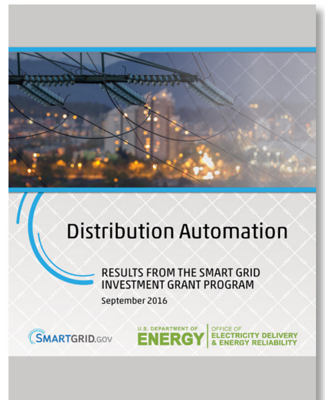
APPENDIX A. SGIG PROJECT INFORMATION, CASE STUDIES, AND KEY REPORTS

Final Reports on SGIG Technology Advancement



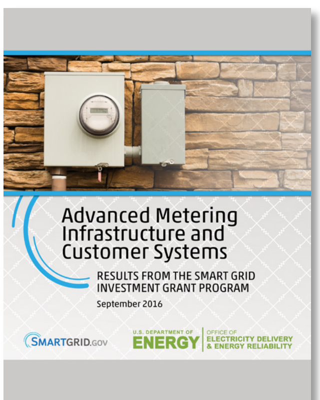
Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009

2016



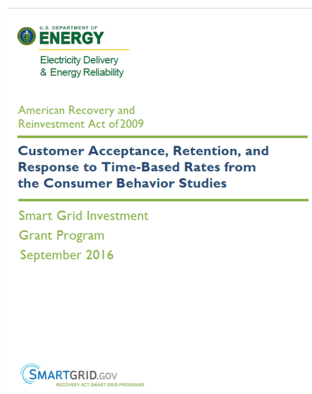
Distribution Automation: Results from the Smart Grid Investment Grant Program

2016



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

2016



Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

2016

SGIG Program 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

SGIG Project Information and Links to Project Pages

Table Legend: AMI – Advanced Metering Infrastructure • CS – Customer Systems • EDS – Electric Distribution Systems • ETS – Electric Transmission Systems

Note: Asterisks after recipient names indicate projects that conducted Consumer Behavior Studies

	Project Funding			Project Type			
SGIG Project Recipient	Federal	Recipient	Total	AMI	CS	EDS	ETS
American Transmission Company (I) Project Webpage | Project Factsheet	1,330,825	1,330,825	2,661,650				•
American Transmission Company (II) Project Webpage | Project Factsheet	10,890,156	10,890,156	21,780,311				•
Avista Utilities Project Webpage | Project Factsheet	20,000,000	20,128,642	40,128,642			•	
Baltimore Gas & Electric Company Project Webpage | Project Factsheet	200,000,000	259,353,902	459,353,902	•	•		
Black Hills Corporation/Colorado Electric Project Webpage | Project Factsheet	5,507,288	5,507,290	11,014,578	•	•		
Black Hills Power Project Webpage | Project Factsheet	9,322,632	9,322,636	18,645,268	•			
Burbank Water and Power, California Project Webpage | Project Factsheet	20,000,000	30,934,209	50,934,209	•	•	•	
CenterPoint Energy Houston Electric Project Webpage | Project Factsheet	200,000,000	445,295,595	645,295,595	•	•	•	
Central Lincoln People's Utility District Project Webpage | Project Factsheet	9,601,696	9,601,700	19,203,396	•	•	•	
Central Maine Power Company Project Webpage | Project Factsheet	95,369,154	96,347,461	191,716,615	•	•		
Cheyenne Light, Fuel and Power Company Project Webpage | Project Factsheet	3,881,070	3,881,070	7,762,140	•			
City of Anaheim Public Utilities Department Project Webpage | Project Factsheet	5,368,182	5,700,233	11,068,415	•		•	
City of Auburn, Indiana Project Webpage | Project Factsheet	2,075,080	2,096,294	4,171,374	•	•	•	
City of Fort Collins Utilities Project Webpage | Project Factsheet	18,101,263	18,161,679	36,262,942	•	•	•	
City of Fulton, Missouri Project Webpage | Project Factsheet	1,502,370	1,502,370	3,004,740	•	•		
City of Leesburg, Florida Project Webpage | Project Factsheet	9,748,811	9,838,445	19,587,256	•	•	•	

SGIG Project Recipient	Project Funding Federal	Recipient	Total	Project Type AMI	CS	EDS	ETS
City of Naperville, Illinois Project Webpage | Project Factsheet	10,994,110	10,994,110	21,988,220	•	•	•	
City of Quincy, Florida Project Webpage	890,355	890,355	1,780,710	•	•		
City of Ruston, Louisiana Project Webpage | Project Factsheet	4,331,650	4,435,635	8,767,285	•	•	•	
City of Tallahassee, Florida Project Webpage | Project Factsheet	7,512,953	7,512,953	15,025,907		•	•	
City of Wadsworth, Ohio Project Webpage | Project Factsheet	5,298,071	5,298,070	10,596,141	•	•	•	
Cleco Power Project Webpage | Project Factsheet	20,000,000	41,786,724	61,786,724	•			
Cobb Electric Membership Corporation Project Webpage | Project Factsheet	15,805,175	15,805,174	31,610,349	•	•		
Connecticut Municipal Electric Energy Cooperative Project Webpage | Project Factsheet	9,188,050	9,188,050	18,376,100	•	•	•	
Consolidated Edison Company of New York Project Webpage | Project Factsheet	136,029,089	136,029,089	272,058,177			•	
Cuming County Public Power District Project Webpage | Project Factsheet	1,874,994	1,874,994	3,749,988		•	•	
Denton County Electric Cooperative Project Webpage | Project Factsheet	17,205,843	23,862,310	41,068,153	•	•	•	
Detroit Edison Company* Project Webpage | Project Factsheet	83,828,878	90,674,664	174,503,542	•	•	•	
Duke Energy Business Services Project Webpage | Project Factsheet	200,000,000	364,618,749	564,618,749	•	•	•	
Duke Energy Carolinas Project Webpage | Project Factsheet	3,826,954	3,826,954	7,653,909				•
El Paso Electric Project Webpage | Project Factsheet	958,339	1,116,448	2,074,787			•	
Electric Power Board of Chattanooga, Tennessee Project Webpage | Project Factsheet	111,567,606	120,651,744	232,219,350	•	•	•	
Entergy New Orleans Project Webpage | Project Factsheet	4,854,510	4,854,510	9,709,019	•	•		
Entergy Services Project Webpage | Project Factsheet	4,610,383	4,611,201	9,221,584				•
FirstEnergy Corporation* Project Webpage | Project Factsheet	57,470,137	57,913,512	115,383,649	•	•	•	

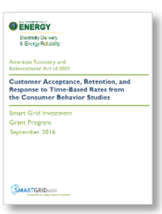
	Project Funding			Project Type			
SGIG Project Recipient	Federal	Recipient	Total	AMI	CS	EDS	ETS
Florida Power & Light Company Project Webpage | Project Factsheet	200,000,000	378,973,324	578,973,324	•	•	•	•
Georgia System Operations Corporation Project Webpage | Project Factsheet	6,456,500	7,888,474	14,344,974				•
Glendale Water & Power Company, California Project Webpage | Project Factsheet	20,000,000	31,302,105	51,302,105	•	•	•	
Golden Spread Electric Cooperative Project Webpage | Project Factsheet	17,263,115	26,839,006	44,102,121	•	•	•	
Guam Power Authority Project Webpage | Project Factsheet	16,603,507	16,610,249	33,213,756	•	•	•	
Hawaii Electric Company Project Webpage | Project Factsheet	5,117,412	5,117,412	10,234,824			•	
Honeywell International Project Webpage | **Project Factsheet**	11,384,363	11,384,363	22,768,726		•		
Idaho Power Company Project Webpage | Project Factsheet	47,000,000	51,270,406	98,270,406	•	•	•	•
Indianapolis Power & Light Company Project Webpage | Project Factsheet	20,000,000	32,700,849	52,700,849	•	•	•	
Iowa Association of Municipal Utilities Project Webpage | Project Factsheet	2,754,628	4,147,855	6,902,483	•	•		
ISO-New England Project Webpage | Project Factsheet	5,955,740	7,939,107	13,894,847				•
Jacksonville Electric Authority Project Webpage | Project Factsheet	12,875,857	13,016,192	25,892,049	•	•		
Knoxville Utilities Board Project Webpage | Project Factsheet	3,585,022	3,894,439	7,479,461	•	•	•	
Lafayette Consolidated Government Project Webpage | Project Factsheet	11,098,802	11,098,802	22,197,604	•	•	•	•
Lakeland Electric* Project Webpage | Project Factsheet	14,849,998	20,231,502	35,081,500	•	•		
M2M Communications Project Webpage | Project Factsheet	2,171,710	2,171,710	4,343,420		•		
Madison Gas and Electric Company Project Webpage | Project Factsheet	5,550,938	5,550,941	11,101,879	•		•	
Marblehead Municipal Light Department* Project Webpage | Project Factsheet	1,346,174	1,473,266	2,819,440	•	•		
Memphis Light, Gas, and Water Division Project Webpage | Project Factsheet	5,063,469	6,420,486	11,483,955			•	

	Project Funding			Project Type			
SGIG Project Recipient	Federal	Recipient	Total	AMI	CS	EDS	ETS
Midwest Energy Project Webpage | Project Factsheet	712,257	712,257	1,424,514				•
Midwest Independent Transmission System Operator Project Webpage | Project Factsheet	16,578,596	16,578,595	33,157,191				•
Minnesota Power* Project Webpage | Project Factsheet	1,544,004	1,547,765	3,091,769	•	•	•	
Modesto Irrigation District Project Webpage | Project Factsheet	1,493,149	2,001,958	3,495,107	•	•	•	
Municipal Electric Authority of Georgia Project Webpage	12,267,350	12,267,350	24,534,700			•	•
Navajo Tribal Utility Authority Project Webpage | Project Factsheet	4,991,750	6,611,825	11,603,575	•			
New Hampshire Electric Cooperative Project Webpage | Project Factsheet	15,210,656	18,882,348	34,093,004	•	•		
New York Independent System Operator Project Webpage | Project Factsheet	35,138,211	35,198,192	70,336,403				•
Northern Virginia Electric Cooperative Project Webpage | Project Factsheet	4,999,997	5,000,000	9,999,997			•	
NSTAR Electric Company Project Webpage | Project Factsheet	10,061,882	10,203,795	20,265,677			•	
NV Energy* Project Webpage | Project Factsheet	138,877,906	138,877,906	277,755,812	•	•		
Oklahoma Gas & Electric Company* Project Webpage | Project Factsheet	130,000,000	204,914,444	334,914,444	•	•	•	
Pacific Northwest Generating Cooperative Project Webpage | Project Factsheet	19,576,743	19,576,743	39,153,486	•	•		
PECO Energy Company Project Webpage | Project Factsheet	200,000,000	215,118,676	415,118,676	•	•	•	
PJM Interconnection Project Webpage | Project Factsheet	13,688,509	13,711,210	27,399,719				•
Pepco – Atlantic City Electric Company Project Webpage | Project Factsheet	18,697,069	19,101,718	37,798,787		•	•	
Pepco – District of Columbia Project Webpage | Project Factsheet	44,576,686	48,168,646	92,745,332	•	•	•	
Pepco – Maryland Project Webpage | Project Factsheet	104,771,940	108,565,024	213,336,964	•	•	•	
Powder River Energy Corporation Project Webpage | Project Factsheet	2,554,807	2,998,421	5,553,228			•	

	Project Funding			Project Type			
SGIG Project Recipient	**Federal**	**Recipient**	**Total**	**AMI**	**CS**	**EDS**	**ETS**
PPL Electric Utilities Project Webpage | Project Factsheet	19,054,516	19,054,516	38,109,032			•	
Progress Energy Service Company (now Duke Energy) Project Webpage | Project Factsheet	200,000,000	326,585,524	526,585,524	•	•	•	•
Public Utility District No. 1 of Snohomish County Project Webpage | Project Factsheet	15,825,817	15,825,817	31,651,634			•	
Qualcomm Atheros Project Webpage | Project Factsheet	3,643,101	3,643,101	7,286,202		•		
Rappahannock Electric Cooperative Project Webpage | Project Factsheet	15,694,096	15,741,778	31,435,874	•	•	•	
Reliant Energy Retail Services Project Webpage | Project Factsheet	19,839,689	28,199,461	48,039,150		•		
Sacramento Municipal Utility District* Project Webpage | Project Factsheet	127,506,261	181,491,890	308,998,151	•	•	•	
Salt River Project Project Webpage | Project Factsheet	56,859,359	57,144,360	114,003,719	•	•		
San Diego Gas & Electric Company Project Webpage | Project Factsheet	28,115,051	31,704,948	59,819,999			•	•
Sioux Valley Energy Project Webpage | Project Factsheet	3,603,593	3,603,594	7,207,187	•	•		
South Kentucky Rural Electric Cooperative Corp. Project Webpage | Project Factsheet	9,538,234	10,606,374	20,144,608	•	•		
South Mississippi Electric Power Association Project Webpage | Project Factsheet	29,804,550	29,989,898	59,794,448	•	•	•	
Southern Company Services Project Webpage | Project Factsheet	164,527,160	198,066,549	362,593,709			•	•
Southwest Transmission Cooperative Project Webpage | Project Factsheet	32,244,485	32,244,485	64,488,970	•	•	•	•
Stanton County Public Power District Project Webpage | Project Factsheet	397,000	397,000	794,000	•			
Talquin Electric Cooperative Project Webpage | Project Factsheet	8,100,000	8,100,000	16,200,000	•	•	•	
Town of Danvers, Massachusetts Project Webpage | Project Factsheet	8,277,567	8,277,567	16,555,134	•	•	•	
Tri-State Electric Membership Corporation Project Webpage | Project Factsheet	1,138,060	1,290,394	2,428,454	•	•		

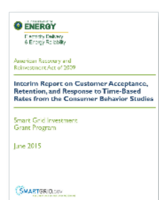
SGIG Project Recipient	Project Funding Federal	Recipient	Total	Project Type AMI	CS	EDS	ETS
Vermont Transco* Project Webpage | Project Factsheet	68,883,585	68,883,585	137,767,170	•	•	•	
Vineyard Power Project Webpage | Project Factsheet	376,610	452,837	829,447		•		
Wellsboro Electric Company Project Webpage | Project Factsheet	431,624	542,378	974,002	•	•		
Westar Energy Project Webpage | Project Factsheet	19,041,565	20,667,603	39,709,168	•	•	•	
Western Electricity Coordinating Council (now Peak Reliability) Project Webpage | Project Factsheet	53,890,000	53,890,000	107,780,000				•
Whirlpool Corporation Project Webpage | Project Factsheet	19,115,410	19,546,855	38,662,265		•		
Wisconsin Power and Light Company Project Webpage | Project Factsheet	3,160,651	3,206,658	6,367,309			•	
Woodruff Electric Cooperative Project Webpage | Project Factsheet	2,357,520	2,658,480	5,016,000	•			

Reports on Consumer Behavior Studies


ENERGY
Electricity Delivery & Energy Reliability
American Recovery and Reinvestment Act of 2009
Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies
Smart Grid Investment Grant Program
September 2016
SMARTGRID.GOV

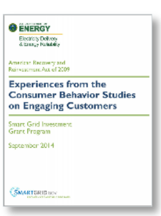
Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

November 2016


ENERGY
American Recovery and Reinvestment Act of 2009
Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies
Smart Grid Investment Grant Program
June 2015
SMARTGRID.GOV

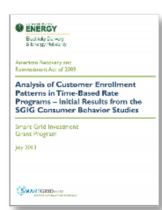
Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies

June 2015


ENERGY
Electricity Delivery & Energy Reliability
American Recovery and Reinvestment Act of 2009
Experiences from the Consumer Behavior Studies on Engaging Customers
Smart Grid Investment Grant Program
September 2014
SMARTGRID.GOV

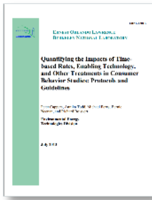
Experiences from the Consumer Behavior Studies on Engaging Customers

September 2014


ENERGY
American Recovery and Reinvestment Act of 2009
Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies
Smart Grid Investment Grant Program
July 2013
SMARTGRID.GOV

Analysis of Customer Enrollment Patterns in Time-Based Rate Programs - Initial Results from the SGIG Consumer Behavior

July 2013



[Quantifying the Impacts of Time-Based Rates, Enabling Technology, and Other Treatments in Consumer Behavior Studies: Protocols and Guidelines](#)

July 2013

[Smart Grid Investment Grant Consumer Behavior Study Analysis: Summary of Utility Studies](#)

June 2013

CBS Utility Evaluation Reports

Participating Utilities	Evaluation Reports	
	Interim	**Final**
Central Vermont Public Service to "Green Mountain Power" – eEnergy Vermont	Sep 2013	Mar 2015
Detroit Edison – SmartCurrents Home Project	Jan 2014	July 2014
First Energy – Smart Grid Modernization Initiative	May 2013	Jun 2015
Lakeland Electric – Smart Metering Infrastructure Initiative	Feb 2015	Apr 2015
Marblehead Municipal Light Department – Residential Dynamic Pricing Pilot Project	May 2012	Jun 2013
Minnesota Power – AMI Behavioral Research	Mar 2014	Forthcoming
NV Energy – Nevada Dynamic Pricing Trial of the Advanced Services Delivery Project	Dec 2014	Oct 2015
Oklahoma Gas and Electric – Smart Study TOGETHER	Mar 2011	Aug 2012
Sacramento Municipal Utility District – SmartSacramento Project	Oct 2013	Sep 2014
Vermont Transco, LLC – eEnergy Vermont	Oct 2013	Jun 2015

ARRA Smart Grid Project Case Studies

Case Study	ARRA Recipient
Demonstrating Coordinated Resources in the Pacific Northwest (Oct. 2015)	Battelle
Power to the People: Advanced Meter Reading Supports Consumer Programs (Oct. 2015)	NSTAR

Case Study	ARRA Recipient
Renovating the Grid and Revitalizing a Neighborhood (Oct. 2015)	Kansas City Power & Light
Smart Grid Technologies Cut Emissions and Costs in Ohio (Oct. 2015)	AEP Ohio
Spinning a Solution to Momentary Electric Grid Disturbances (Oct. 2015)	Hazle Spindle
Voltage and Power Optimization Saves Energy and Reduces Peak Power (Oct. 2015)	American Electric Power, Battelle, Kansas City Power & Light, National Rural Electric Cooperative Association
East Penn Manufacturing Delivers New Battery Technology for Electrical Grid Support (Oct. 2015)	East Penn
Energy Storage System Firms a Renewable Resource (Oct. 2015)	Public Service Company of New Mexico
Energy Storage with Staying Power (Oct. 2015)	Aquion
Harnessing New Generation and Storage Technologies for the Grid (Oct. 2015)	Center for the Commercialization of Electric Technologies
Improving Efficiency with Dynamic Line Ratings (Oct. 2015)	New York Power Authority
Improving Security in the Growing Smart Energy Corridor (Oct. 2015)	Long Island Power Authority
Making Electricity a Value Proposition for the Consumer (Oct. 2015)	Pecan Street
New Forecasting Tools Enhance Wind Energy Integration in Idaho and Oregon (Sep. 2014)	Idaho Power Company
Automated Demand Response Benefits California Utilities and Commercial/Industrial Customers (Sep. 2014)	Honeywell International
Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas (Sep. 2014)	Duke Energy Business Services
Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York (Aug. 2014)	Consolidated Edison Company of New York
Control Center and Data Management Improvements Modernize Bulk Power Operations in Georgia (Aug. 2014)	Georgia System Operations Corporation
Oncor's Pioneering Transmission Dynamic Line Rating Demonstration Lays Foundation for Follow-On Deployments (Apr. 2014)	Oncor
Smart Meter Investments Benefit Rural Customers in Three Southern States (Mar. 2014)	Tri-State Electric Membership Corporation
Smart Meter Investments Yield Positive Results in Maine (Jan. 2014)	Central Maine Power Company

Case Study	ARRA Recipient
Demand Response Defers Investment in New Power Plants in Oklahoma (Apr. 2013)	Oklahoma Gas and Electric Company
Smart Grid Solutions Strengthen Electric Reliability and Customer Services in Florida (Jul. 2012)	Florida Power & Light Company
Critical Peak Pricing Lowers Peak Demands and Electric Bills in South Dakota and Minnesota (Jun. 2012)	Sioux Valley Energy
Transforming Electricity Delivery in Florida (Apr. 2012)	Talquin Electric Cooperative
CenterPoint Energy's Smart Grid Solutions Improve Operating Efficiency and Customer Participation (Mar. 2012)	CenterPoint Energy Houston Electric
Glendale, California Municipal Invests in Smart Grid to Enhance Customer Services and Improve Operational Efficiencies (Mar. 2012)	City of Glendale Water & Power
A "Model-Centric" Approach to Smarter Electric Distribution Systems (Jan. 2012)	Consolidated Edison Company of New York
Building a Smarter Distribution System in Pennsylvania (Jan. 2012)	PPL Electric Utilities
Pacific Northwest - Battelle Smart Grid Demonstration Project 2012 Annual Report (Dec. 2011)	Battelle
Vermont Pursues a Statewide Smart Grid Strategy (Dec. 2011)	Vermont Transco
Agricultural Demand Response Program in California Helps Farmers Reduce Peak Electricity Usage, Operate More Efficiently Year–Round (Dec. 2011)	M2M Communications
At the Forefront of the Smart Grid: Empowering Consumers in Naperville, Illinois (Oct. 2011)	City of Naperville, Illinois
Smarter Meters Help Customers Budget Electric Service Costs (Oct. 2011)	Tri-State Electric Membership Corporation
Synchrophasor Technologies for a Better Grid (Aug. 2011)	American Transmission Company (2 projects); Duke Energy Carolinas LLC; Entergy Services; PJM Interconnection; ISO New England; Midwest Energy; New York Independent System Operator; Western Electricity Coordinating Council
Smart Meter Investments Support Rural Economy in Arkansas (Aug. 2011)	Woodruff Electric
Bright Lights, Big City: A Smarter Grid in New York (Jun. 2011)	Consolidated Edison Company of New York

Case Study	ARRA Recipient
A Smarter Electric Circuit: Electric Power Board of Chattanooga Makes the Switch (Jun. 2011)	Electric Power Board
Reducing Peak Demand to Defer Power Plant Construction in Oklahoma (Jun. 2011)	Oklahoma Gas and Electric Company
A Smart Grid Strategy for Assuring Reliability of the Western Grid (Jun. 2011)	Western Electricity Coordinating Council
National Rural Electric Cooperative Association - Helping America's Electric Cooperatives Build a Smarter Grid to Streamline Operations and Improve Service (May 2011)	National Rural Electric Cooperative Association