Advanced Metering Infrastructure and Customer Systems

RESULTS FROM THE SMART GRID INVESTMENT GRANT PROGRAM

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

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Executive Summary

Advanced metering infrastructure (AMI) 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 in-home displays and programmable communicating thermostats, 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.

This report shares key results and benefits from the 70 SGIG projects implementing AMI and customer system technologies, and also documents lessons learned on technology installation and implementation strategies. With this report, the U.S. Department of Energy (DOE) aims to further accelerate grid modernization by helping decision makers better assess the benefits and costs of AMI and customer system investments and learn from leading-edge utilities.

The Smart Grid Investment Grant (SGIG) Program

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

Deployment of AMI and customer systems accounted for more than two-thirds of the $7.9 billion total SGIG investment. SGIG projects invested in new communication networks and information management systems that form the backbone of AMI, and tested:

- ✓ 16.3 million smart meters—29% of total U.S. smart meters installed by 2014
- ✓ 250,000 programmable communicating thermostats (PCTs)
- ✓ 400,000 direct load control (DLC) devices
- ✓ 100,000 in-home displays (IHDs)
- ✓ 417,000 participants in time-based rate and incentive programs
- ✓ 49 customer web portals

Major Findings

SGIG projects demonstrated that AMI and customer systems can achieve substantial grid impacts and benefits for customers and utilities, including:

- → **Reduced costs for metering and billing** from fewer truck rolls, labor savings, more accurate and timely billing, fewer customer disputes, and improvements in operational efficiencies.
- → **More customer control over electricity consumption, costs, and bills** from greater use of new customer tools (e.g., web portals and smart thermostats) and techniques (e.g., shifting demand to off-peak periods).
- → **Lower utility capital expenditures and customer bill savings** resulting from reduced peak demand and improvements in asset utilization and maintenance.
- → **Lower outage costs and fewer inconveniences for customers from faster outage restoration** and more precise dispatching of repair crews to the locations where they are needed.

Operations and maintenance (O&M) cost savings from remote billing and metering services is a major benefit stream for the AMI business case. Operational efficiencies enhanced revenue collection and improved customer service and satisfaction.

- Remote meter reading generates more timely, accurate bills, eliminating the need for manual truck rolls and labor to read meters, connect/disconnect service, and diagnose many meter issues. 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 enables utilities to proactively identify and notify customers of unusual usage patterns in advance of bills.
- Pre-pay billing plans helped customers to manage consumption and costs. Several utilities improved revenue collection and cost recovery by implementing pre-pay billing programs that can help customers avoid defaulting on bills.
- New capabilities for tamper and theft detection through AMI deployments enhance revenue collection and lower costs.

> Over a 3-year period, SGIG projects cumulatively:[1]
>
> Saved $316 million in O&M costs—an average of $16.6 million per project reporting
>
> Avoided 13.7 million truck rolls and 68.3 million vehicle-miles traveled
>
> Saved an estimated 15,160 tons of CO_2 equivalent emissions

> 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 became an important contributor to outage management, service restoration, and voltage monitoring for many SGIG projects, particularly those that implemented AMI alongside investments in distribution automation technologies.

- AMI enables utilities to isolate outages faster and dispatch repair crews more precisely, reducing outage duration, limiting inconvenience, and reducing labor hours and truck rolls for outage diagnosis and restoration.
- Utilities facing regular, severe weather events and storm-induced outages have greater incentives for using AMI for outage management than those that do not.

> Burbank Water and Power sends last-gasp alerts from its smart meters to the Outage Management System within 2 minutes, where its Geographic Information System updates an outage map.

[1] O&M cost savings data: 19 projects reporting from 2011-2014; avoided truck roll data: 42 projects reporting from summer 2011-winter 2014; avoided vehicle-miles: 21 projects reporting from summer 2011-winter 2014; emissions data: analysis of vehicle operations data from 31 SGIG projects from April 2011-March 2015.

- AMI data integration with other information and management systems, including outage management systems (OMS) and geographic information systems (GIS), 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.
- 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 conservation voltage reduction (CVR) programs.

Central Lincoln Peoples Utility District piloted a CVR program that resulted in a 2% energy savings for all customers—and plans to implement it system-wide

AMI and customer systems provided utilities with new capabilities to offer time-based rate, incentives, and DLC programs. This enabled utilities to reduce peak demand, lower wholesale power purchase costs, sell excess electricity to regional markets, and defer investments in new generation and delivery capacity.

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), 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 programmable communicating thermostat (PCT) automation enabled greater peak demand reductions than manual responses. Participating customers at five CBS utilities testing PCTs reduced average peak demand by 30% with CPP and 29% with CPR.
- In-home displays (IHDs) were less helpful, and in many cases, participating customers declined to use them or used them for a short period of time.

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

Key Lessons and Conclusions

Many Factors Affect the AMI Business Case

AMI system implementation costs and benefits varied widely across the projects, for a variety of reasons discussed below. For example, the per-meter deployment cost ranged from $130 to $1,895 per meter across the SGIG projects. However, only six projects reported a total installation cost above $600 per meter. The range of O&M cost savings across projects was also large: 19 projects reported a cumulative three-year savings of $316 million, yet more than $174 million of that was saved by one project alone. These results gave important insight into the multiple factors that determine an individual utility's AMI implementation cost and return on investment:

- **Full- and partial-scale implementations generally had a lower total cost per meter** than pilot-scale projects because AMI communications network upgrades, data management system integration, and other fixed installation costs make up more than half of the total cost per meter on average. These costs varied for each utility based on the scope of the project.
- **Communication networks upgrades designed to support additional smart grid functionalities beyond AMI** raised the total cost for some utilities, but increased the value of the investment and helped utilities set the stage for future grid modernization.
- **Purchasing and enabling multiple smart meter features and integrating AMI with a larger number of systems** can both raise the total AMI implementation cost, but also increase the value of benefits to support the business case.
- **The utility's level of experience with AMI systems** and the pre-project state of the existing communications, data management, and metering systems largely affected the overall cost.
- **Geographically dispersed utilities with low customer densities in some cases found a favorable business case** for AMI from the operational savings alone.
- **Customer outreach and education** contributed to overall cost, and varied by project.

Communications Networks Create More Value When Designed to Serve Smart Grid Technology Needs Beyond AMI

Utilities accrue additional advantages when they design communications networks that have the bandwidth, latency requirements, and capacity to serve other needs, such as distribution automation (DA) and demand-side management (DSM), in addition to metering and billing.

More robust communications networks constitute the backbone of not only a smart grid, but also smart cities. Several 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 city services beyond electricity metering—such as gas and water metering and internet services.

Systems Integration is a Critical Linchpin for AMI Impacts and Benefits

Efficient and accurate billing and metering services require integration of AMI, meter data management systems (MDMS), customer information systems (CIS), and billing systems. Further integrating AMI with OMS, distribution management systems (DMS), and other DA systems can increase the benefits of each individual smart grid technology—making system integration both a top priority *and* a major technical challenge for many utilities.

Integrating meter data with other systems and functions often 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. Integration of AMI and CIS with web portals, time-based rates, incentive programs, and customer devices such as PCTs, IHDs, home area networks (HANs), and energy management systems is also a new area involving rapidly evolving technologies and needs for upgraded standards and data transfer protocols. In addition, it is essential to integrate cybersecurity and interoperability for smart grid success.

Workforce Management and Training are Critical to AMI Success

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.

Future Directions and Next Steps

With the SGIG projects complete, the majority of SGIG recipients are building upon project results by expanding technology deployments, offering successful pilot programs to more customers, or improving the integration of AMI with other data and information management systems to extract additional value or activate new smart meter capabilities that were not yet tested. Many utilities with pilot AMI deployments now plan to expand smart meters to more customers.

DOE continues to support grid modernization through research, development, demonstration, analysis, and technology transfer activities. New technologies are driving changes in electric power on multiple fronts. The need for stronger national efforts to modernize the grid for the cost-effective integration of renewable and distributed generation, energy efficiency and demand response, and cybersecurity and interoperability standards is essential.

While the SGIG program is now complete, grid modernization and consumer engagement remain important national priorities. DOE's Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid, and how DOE will enable this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will assist DOE in developing and implementing the activities in the MYPP.[2]

AMI deployments highlighted several continuing challenges for grid modernization that the industry should address to maintain momentum from the SGIG projects:

- Advances in data analytics could help utilities extract additional benefits from the large volume of interval load data produced by AMI.
- Consistent data formats and more comprehensive interoperability standards are needed to achieve optimal levels of interoperability for smart meters, customer devices, and communications and information systems.
- Maintaining strong cybersecurity and customer privacy protections will be a key focus for utilities as AMI deployments grow.
- There are many opportunities to make smart appliances and building energy management equipment on the customer's side of the meter more "grid-friendly."
- Continued innovations in mobile device applications and tools can make near-real-time data on consumption and costs available to customers when and how they need it.

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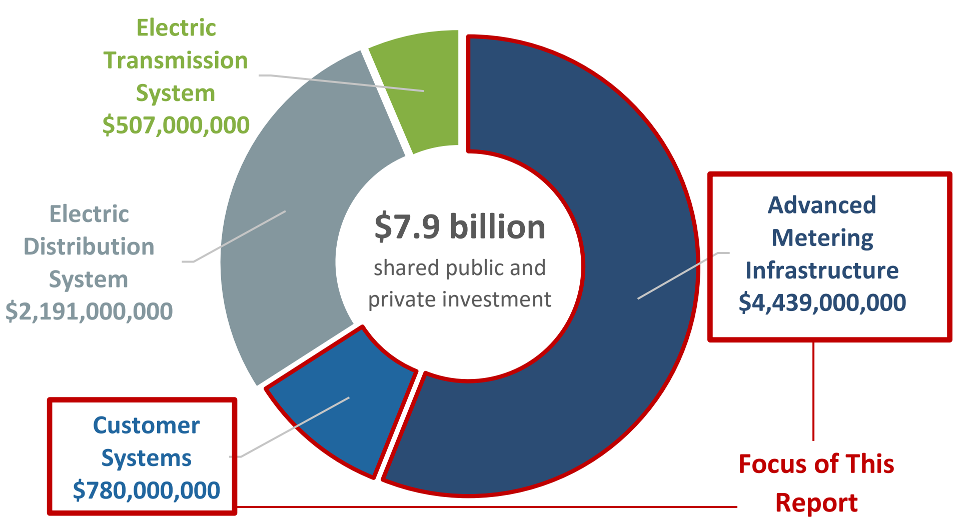
[2] DOE, Grid Modernization Initiative, *Grid Modernization Multi-Year Program Plan*, November 2015.

1 AMI and Customer System Deployment in the Smart Grid Investment Grants

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

The large public and private investments made under ARRA have accelerated smart grid technology deployments, providing real-world data on technology costs and benefits along with valuable lessons learned and best practices. This report informs electric utilities, policymakers, and other key stakeholders of the qualitative and quantitative impacts, benefits, costs, and lessons learned from SGIG projects that implemented advanced metering infrastructure (AMI) and customer systems. The SGIG program concluded in 2015, making this DOE's final report on AMI and customer system results.

Figure 1. Breakdown of $7.9 Billion SGIG Investment



Industry and government collectively invested $5.21 billion in projects testing one or more AMI and customer technologies—accounting for more than two-thirds (67 percent) of the total SGIG investment. Projects with AMI or customer systems components represent 70 of the 99 total SGIG recipients. Electric utilities led 67 of the AMI and customer system projects, while vendors or service providers led the remaining 3.[3] While nearly all projects deployed a combination of both AMI and customer system technologies, six program participants focused only on customer systems.

[3] The three non-utility projects were led by Honeywell, M2M, and Whirlpool.

(Many of these 70 AMI and customer system projects also installed new distribution automation [DA] technologies and systems. Project results specific to those DA technologies are reported separately in *Distribution Automation: Results from the SGIG Program*.)

Participants used the funds to purchase, test, and install hardware and software; conduct training; improve cybersecurity protections; integrate smart grid technologies with key utility systems; collect and analyze data; and conduct other tasks needed for successful completion of project objectives.

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

1.1 AMI and Customer Technologies and Functions Deployed in SGIG

AMI applies smart control and communication technologies to automate metering functions that have been typically accomplished through manually intensive operations, including electricity meter readings, service connection and disconnection, tamper and theft detection, fault and outage identification, and voltage monitoring. Combined with advanced customer-based technologies, AMI also enables utilities to offer new rate options that incentivize customers to reduce peak demand and energy consumption (see Figure 2).

AMI deployment typically consists of three key components:

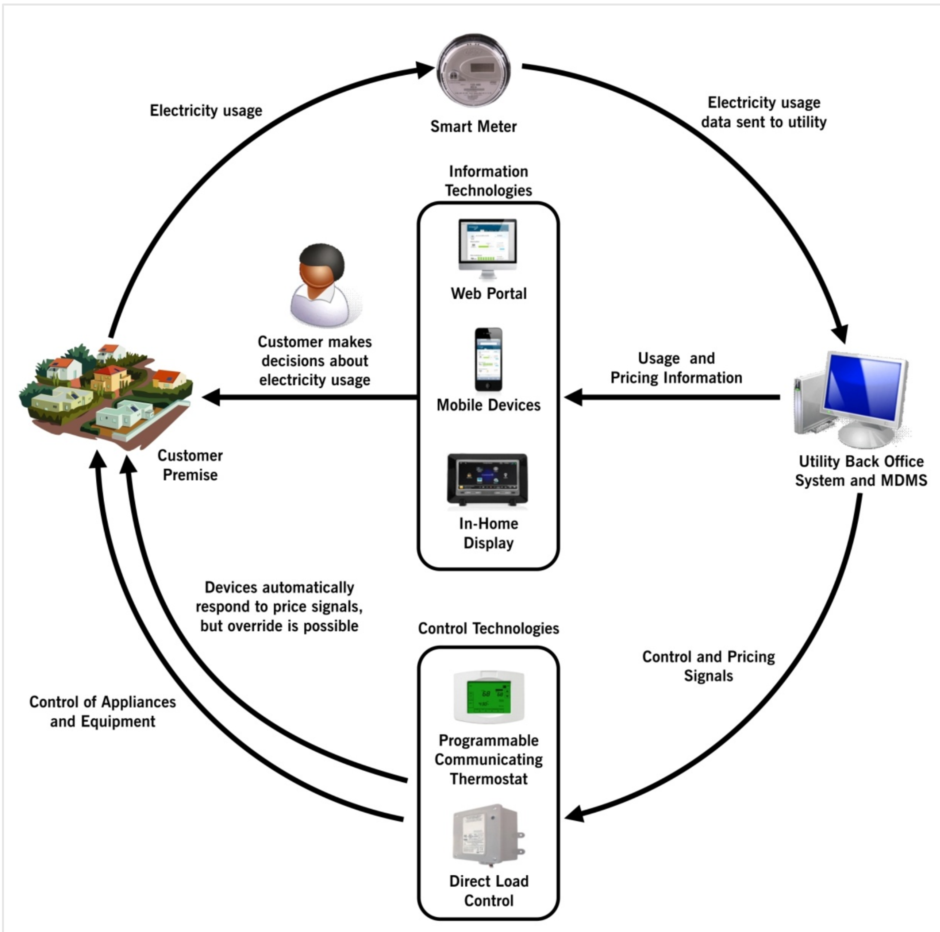
- → **Smart meters** installed at the customer's premise that typically collect electricity consumption data in 5-, 15-, 30-, or 60-minute intervals.
- → New or upgraded **communications networks** to transmit the large volume of interval load data from the meter to the utility back offices.
- → A **meter data management system (MDMS)** to store and process the interval load data, and to integrate meter data with one or more key information and control systems, including head-end systems, billing systems, customer information systems (CIS), geographic information systems (GIS), outage management systems (OMS), and distribution management systems (DMS). (Not all utilities used an MDMS.)

Customer systems include both information and control technologies that aim to help customers more actively manage their electricity consumption and associated costs—particularly in response to time-based rates:

- → *Control technologies* include devices such as **programmable communicating thermostats (PCTs)** and **direct load control (DLC) devices** that utilities and customers use to automatically control customers' heating and cooling systems or other energy-intensive devices. In addition, **home-area networks (HAN)** and **energy management systems** can be installed to automatically control appliances in response to price signals, load conditions, or pre-set preferences.

→ *Information technologies* encourage customers to better manage their electricity consumption by providing them with near real-time data about their electricity consumption and costs through **in-home displays (IHDs), web portals, and text/email**. Web portals and IHDs provide information in visually appealing ways to improve understanding and insight about actions that can save energy and reduce bills. Web portals often provide electricity "dashboards" that give customers access to their historical and near-real-time usage information. IHDs and mobile devices offer alerts on electricity usage and notification of critical peak events.

Figure 2. AMI and Customer Systems Work Together to Automate Functions and Manage Demand-Side Consumption

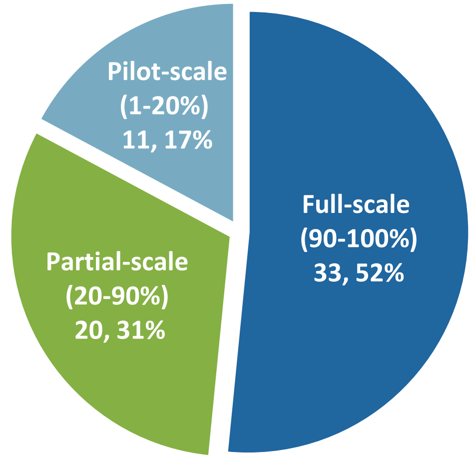


Advanced Metering Infrastructure

Over half of the 64 AMI utilities implemented full-scale smart meter deployments that covered more than 90 percent of customers (see Figure 3). These projects used DOE funds to modernize their entire metering infrastructure and most took advantage of several of the new functions and capabilities enabled by AMI.

Eleven projects chose to deploy smart meters on a pilot scale (to less than 20 percent of customers), seeking to test meter installation and operation, and find the most cost-effective applications, before deciding to commit to system-wide deployments. The 20 remaining SGIG AMI projects implemented partial deployments, and may later expand to system-wide deployments. SGIG funding accelerated plans and enabled broader use of new AMI functions and capabilities for all participating utilities.

Figure 3. Scale of SGIG AMI Deployments (% of Utility System)



(64 projects reported this data point)

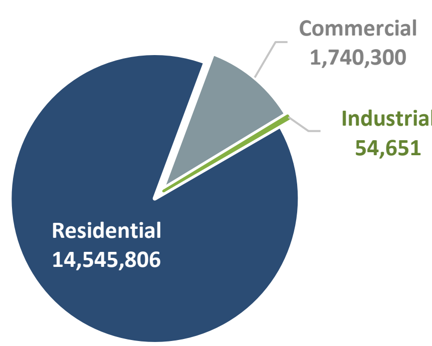
Smart Meters

The core element of AMI is smart meters, which provide a number of functions, including measuring customer electricity consumption on 5-, 15-, 30-, or 60-minute intervals; measuring voltage levels; and monitoring the on/off status of electric service. Smart meters communicate these readings to utilities for processing, analysis, and re-communication back to customers for billing, energy feedback, and time-based rates.

When the projects began in 2009, only 9.6 million smart meters were installed in the United States. SGIG utilities deployed more than **16.3 million smart meters**—representing about 29 percent of the 58.5 million smart meters installed nationwide by 2014.[4] The vast majority of those were installed for residential customers (89 percent), while 10 percent were commercial installations and 1 percent were industrial installations (see Figure 4).

Smart meters were the most numerous assets deployed in the SGIG Program and are a key enabling technology. In addition to remote meter reading, smart meters can provide other important functions, such as remote connect/disconnect, tamper detection, outage monitoring, voltage monitoring, and bidirectional measurement of electricity use to better enable adoption of distributed generation and dynamic pricing. Without smart meters, and the communications and information management systems that connect them, many of the cost savings and demand-reducing impacts and benefits from AMI and customer systems could not be realized.

Figure 4. SGIG Smart Meter Installations by Customer Type



Communications Networks and Systems

New smart meter capabilities require **communications networks** that are capable of delivering accurate, reliable, and voluminous streams of data in a timely manner. These communication networks connect smart meters to **head-end systems**, which manage data communications between smart meters and other information systems including MDMS, CIS, OMS, and DMS. The head-end system transmits and

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

receives data, sends operational commands to smart meters, and stores interval load data from the smart meters to support customer billing.

Most SGIG utilities installed new or upgraded communication networks to deploy smart meters. They leveraged a variety of wired and wireless communications technologies (see Table 1), considering how each technology fits with their operational goals, service area characteristics, and business process constraints. Utilities typically customized their own systems, combining multiple approaches and integrating with both legacy and new systems involving multiple vendor products.

In addition, many utilities use common communications platforms to support multiple field devices including smart meters, customer systems, and distribution automation (DA) equipment. For example, fiber backhaul and wireless radio networks may use one protocol to support communications for automated feeder switching and another for smart metering.

Table 1. Examples of AMI Communications Technologies

Wired	Wireless
• Fiber optic cable • Power-line communications (PLC) • Telephone dial-up modem • Digital subscriber line (DSL)	• Radio Frequency (RF) – mesh network • RF – Point to multipoint • RF – Cellular

Choosing the most suitable communication technologies and configurations required utilities to examine multiple requirements, considering all smart technologies that may use the networks:

- Bandwidth
- Latency
- Cost
- Reliability and coverage
- Spectrum availability[5]
- Backup power needs
- Cybersecurity considerations

While there is no standard approach or configuration for communications networks that support AMI operations, most utilities use two-layer systems to communicate between head-end systems and smart meters. Typically, the first layer of the network connects intermediate data collection points (e.g., substations and communications towers) with headquarters' operations and consists of high-speed, fiber optic, power-line communications (PLC), microwave, and RF-cellular systems for backhauling large volumes of data. Some utilities use existing supervisory control and data acquisition (SCADA) communications systems to support this layer. The second layer of the network typically connects the intermediate collection points with smart meters and use RF mesh and PLC communications networks. Many SGIG AMI and customer systems projects chose high-speed fiber optic or third-party cellular network for backhaul. Wireless radio mesh network was a common choice for field communications network.

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

Integration with Information and Management Systems

Participating utilities aimed to extract as much value as possible from their smart meter deployments by integrating smart meter data with one or more information and data management systems, including:

→ **MDMS**: process and store interval load data for billing systems, web portals, and other information systems.

→ **Billing systems**: process interval load data to automate bill generation.

→ **CIS**: process data from MDMS and connect with billing systems for storing data on customer locations, demographics, contact information, and billing histories.

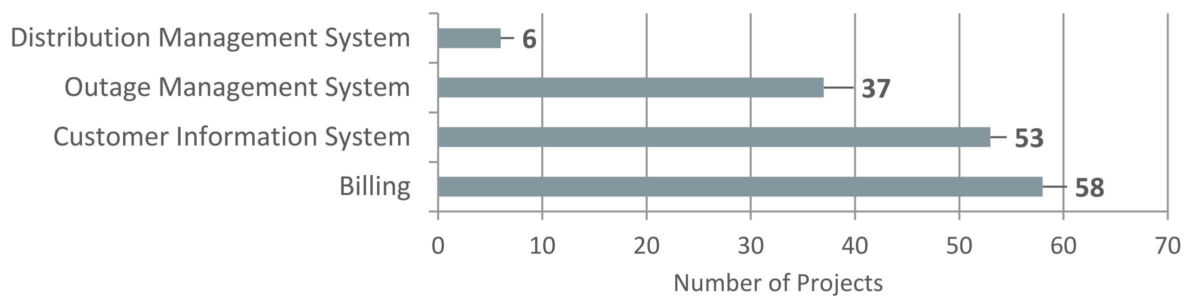
→ **OMS**: process data about meter on/off status to isolate outage locations and often connect with **GIS** for dispatching repair crews and managing the restoration of services. Outage data from smart meters is made more valuable to grid operators when it is integrated with GIS and data from customer call centers

→ **DMS**: process data on outages and customer voltage levels for implementing electric reliability and voltage and volt-ampere reactive (VAR) optimization procedures.

Legacy information and management systems—billing, CIS, OMS, and DMS—were not designed to handle large volumes of interval load data from smart meters. As a result, information and management systems integration is a necessary and ongoing process for all utilities involved in AMI deployment.

Nearly all SGIG utilities integrated AMI with billing systems. CIS and OMS systems were also popular integration choices (see Figure 5). Only six utilities chose to integrate with DMS, as few utilities were yet testing all functions of their new smart meters, such as voltage monitoring, for example. It is anticipated that more utilities will be integrating AMI with DMS as systems mature.

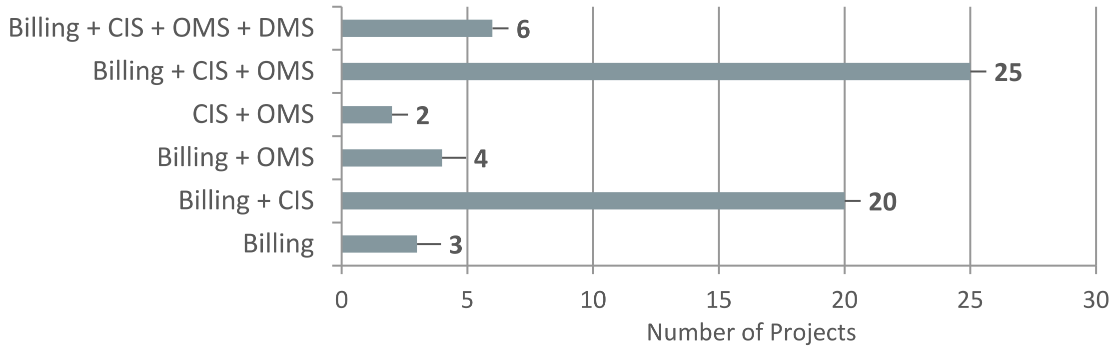
Figure 5. Projects Integrating AMI with Key Information and Management Systems



(60 AMI projects reported this data point)

Integrating AMI with *multiple* information and management systems unlocks a variety of new functions that improve the efficiency of grid operations. For example, smart meter data can be used for load research and forecasting, and to understand the effectiveness of demand-side programs given time of day, weather, and season. Almost half of the SGIG AMI utilities (42 percent) integrated AMI with billing, CIS, and OMS, while 33 percent integrated AMI with just billing and CIS (see Figure 6).

Figure 6. Projects Integrating AMI with Various Combinations of Information and Management Systems



(60 AMI projects reported this data point)

Customer Systems

The SGIG utilities installed more than 400,000 DLC devices and more than 250,000 PCTs (see Table 2). These control technologies were the most numerous devices deployed, as the utilities generally had the most experience with this equipment. Customers received incentives for allowing utilities to use DLC devices to control various types of appliances and equipment—such as air conditioners, water heaters, and swimming pool and irrigation pumps—to reduce peak demands. PCTs were also used to reduce peak demands. During critical peak event days, the devices received signals from the utility to automatically raise air conditioner set points during peak periods and then automatically lower them when peak periods were over. PCTs were controlled by customers and were often used in conjunction with event-driven, time-based rates such as critical peak pricing (CPP) or critical peak rebate (CPR). In addition, HANs and energy management systems were installed to automatically control appliances in response to price signals, load conditions, or pre-set preferences.

Table 2. Number of Customer Systems Installed under SGIG

Direct Load Control Device	413,734
Programmable Communicating Thermostat	262,183
In-Home Display	21,228
Energy Management System	2,379
Smart Appliance	368

Other customer systems deployed included more than 20,000 IHDs, 368 smart appliances, and web portals offered by 49 utilities. These information technologies were used to a lesser extent due to greater unfamiliarity with the technologies and their potential benefits and impacts. These information displays can be designed to guide customers about ways to reduce peak demand or achieve electricity conservation. IHDs are devices installed in homes that display consumption data in various formats for customers. Most of the projects offered web portals that contain energy and billing dashboards tailored for each participating customer. In addition, several utilities offered energy usage and cost information via text message, email, or phone calls for laptop, tablet, and mobile phone access.

Smart appliances such as refrigerators and dishwashers come pre-installed with "smart chips" and can send or receive signals that enable the timing of certain functions (e.g., defrost cycles) to be remotely controlled. SGIG projects tested control of only a few hundred smart appliances. Power companies and equipment manufacturers are working to further advance software, standards, and protocols for smart appliances.

In general, residential customer systems are relatively new, with much still unknown about cost-effectiveness and customer acceptance. This report describes results from the limited number of SGIG utility experiences. While SGIG projects reported on the costs of customer system implementation, a lack of consistency in how each utility defined and measured cost categories did not result in consistent aggregated cost data. The Project Information Page on SmartGrid.gov includes individual project information on costs and benefits.

Time-Based Rates and Demand-Side Programs

The deployment of AMI technologies in tandem with customer-based systems unlocked new capabilities for SGIG utilities to offer **time-based rates and incentive-based programs** that encourage customers to reduce electricity use, primarily during peak periods.

Time-based rate programs come in many forms and offer various levels of electricity prices that may differ by the hour, day, or month. As such, these rate programs typically charge more for electricity during times when power supply costs and demand are relatively high (such as hot summer days), and less during times when power supply costs and demand are relatively low. Some utilities offered incentive-based programs instead of, or in addition to, time-based rate programs to achieve demand-side objectives.

Table 3 demonstrates how SGIG utilities were able to offer new demand-side management (DSM) functions only by deploying a combination of AMI and customer system technologies.

Table 3. AMI and Customer Systems Combine to Enable New Demand-Side Functions

	AMI and Customer Assets, Technologies, and Systems	AMI-Enabled DSM Programs		
		Time-Based Rate Programs	Direct Load Control Programs	Information and Education Programs
AMI	**Smart meters**	●	●	●
	MDMS	●	●	●
	AMI communications systems	●	●	●
	Backhaul systems	●	●	●
	CIS	●	●	●
Customer	**PCTs**	●	●	
	IHDs	●		●
	HANs	●		
	Energy management systems	●		
	Appliance and equipment switches		●	
	Web portals			●

A total of 26 projects tested one or more time-based rate options in combination with various customer systems. Ten SGIG utilities also participated in special Consumer Behavior Studies (CBS), which evaluated customer acceptance, retention, and response, and addressed the cost-effectiveness of using time-based rates to achieve utility, customer, and societal objectives. Highlighted results are included in Section 3 and detailed results and lessons learned can be found on the SGIG-CBS website.

1.2 Project Build and Impact Metrics

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

At the outset of the SGIG program, DOE collaborated with each of the project teams to develop a Metrics and Benefits Reporting Plan (MBRP) outlining how the utility would collect and report metrics over the course of the project. DOE analysis of the SGIG AMI and customer systems projects involved the assessment of four key components (see Figure 7), along with lessons learned.

Figure 7. SGIG Analysis Process

- ***Assets*** (e.g., smart meters and DLC devices)
- ***Functions*** (e.g., remote service connections/disconnections and demand management)
- ***Impacts*** (e.g., reduced truck rolls and lower peak demands)
- ***Benefits*** (e.g., lower operating costs and reduced customer bills)

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

1.3 Key Data Limitations and Considerations

Each utility had a different level of experience and expertise with AMI and customer systems at the project outset, and deployed technologies at widely different scales. Full-scale technology deployment yielded larger grid impacts. More experienced utilities faced fewer hurdles and saw results more quickly. Utilities that had steeper learning curves were primarily interested in testing and learning—rather than generating large grid and customer impacts—and therefore yielded limited impact data.

Several factors are important to consider when evaluating report data:

- **The AMI and customer systems projects deployed technologies at different scales, and not all of the 70 participating utilities deployed every technology or tested out every function—making it difficult to meaningfully aggregate data on technology cost, performance, and benefits across all 70 projects**. For example, some projects tested only remote connect/disconnect and tamper detection functions, while others tested only outage reporting or voltage monitoring functions. About 52 percent had greater than 90 percent deployment of AMI, while 17 percent deployed AMI to less than 20 percent of their systems.

    - Utilities only reported on data points relevant to their projects, and therefore the population size for each data point varies—which is why there are notations such as “50 projects reported this data point” in charts or graphs throughout the report.

- **Utilities did not always use uniform categories to measure and report purchasing, installation, and implementation costs, making it difficult to accurately** differentiate between several line items for data analysis.

- **Reported asset costs from one utility cannot be directly compared to another utility. Individual case studies include certain project costs and benefits to provide a range of examples on the technology cost-benefit ratio.** Costs vary greatly from utility to utility based on their project size, system design, and previously installed systems and technologies. In addition, equipment costs for certain devices have also changed since the program began in 2010.

- **Some utilities had trouble establishing reliable historical baselines from which to measure improved performance.** Accurately measuring the impact of AMI and customer system technologies required consistent measurement of historical performance—before the technologies were implemented. Several utilities underestimated the time, effort, and engineering expertise required to accurately measure smart grid impacts and historical baselines.

2 Major AMI Findings: Improved Customer Service and Reduced Operational Costs

All SGIG AMI utilities used smart meters for automated meter reading—which was the primary driver of utility investment in AMI because of its ability to eliminate costly meter operations and automate bill generation. Many utilities also purchased smart meters with one or more additional functions: remote meter connection and disconnection, tamper detection, outage monitoring, and voltage monitoring (see Table 4). About 64 percent implemented all four of the other main smart meter functions.

Table 4. Number of Projects Implementing Combinations of Smart Meter Functions

Smart Meter Functions				Number of Projects
Remote Connect/ Disconnect	Tamper Detection	Outage Monitoring	Voltage Monitoring	
•	•	•	•	38
•	•			7
•	•	•		5
•		•		3
	•			2
		•	•	2
	•	•		1
•				1

(59 AMI Projects reported this data point)

The vast majority of the 53 utilities that enabled tamper detection did so for over 90 percent of their smart meters. Tamper detection is usually performed on aggregate smart meter data in the MDMS. In contrast, utilities may choose to implement remote connection and disconnection capabilities only on feeders with relatively high levels of customer turnover. Less than half of the 55 utilities that enabled remote connection/disconnection enabled the feature on at least 90 percent of their smart meters.

2.1 Automated Billing and Remote Meter Reading, Connection, and Disconnection

The primary new capability driving AMI investments is the ability to generate automated, timely, and accurate bills, regardless of weather conditions or property access limitations, which traditionally hamper collection of meter information. Once properly configured, AMI and billing systems generate more consistent and accurate bills automatically, with fewer recording errors and customer complaints. Because data intervals can be specified in 15-minute increments, utilities can customize billing periods based on customer preferences rather than on meter reading schedules set by the utility. Utilities can also supply customers with tailored supplemental usage and service quality information as added features in either paper or electronic form.

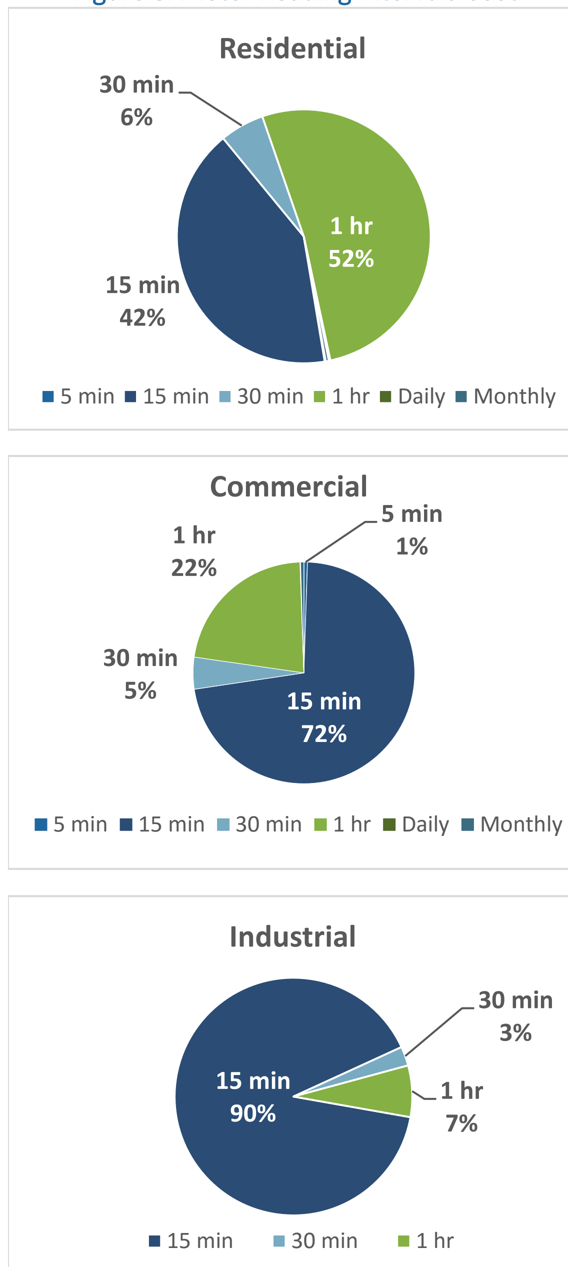
AMI also enables remote connections and disconnections and on-demand, out-of-cycle meter readings. Remote service switching is the capability to turn meters on and off to support changes in occupancy, reoccurring non-payment issues, and prepaid service offerings. In cases of emergency, the remote service switch may be used to support firefighters and other first responders.

These services previously would have required scheduling service appointments and waits of up to several days for service trucks to arrive. On-demand services are particularly valuable for seasonal or temporary residents who typically have variable schedules and needs for assistance.

For residential customers, utilities most used 1-hour meter-reading intervals, which is sufficient for billing purposes and is the way most utilities use the data in web portals when presenting feedback about electricity consumption to customers. For commercial and industrial customers, utilities mostly used 15-minute meter-reading intervals. The shorter intervals are necessary when bills also include demand charges. Figure 8 shows the distribution of meter reading intervals used by the SGIG projects.

Customers with concerns about high bills or unusual consumption patterns can access or request bill information on demand using the utility's web portal or calling a utility's customer service representatives.

Figure 8. Meter Reading Intervals Used



Key Result: Operations and Maintenance Cost Savings

Operations and maintenance (O&M) cost savings from remote billing and metering services is one of the most significant benefit streams for AMI business case analysis.

In total, SGIG utilities using AMI for remote meter reading and meter service orders avoided 13,785,708 meter operations truck rolls[6] and 68,374,295 vehicle-miles traveled[7] from the summer of 2011 to the winter of 2014. The reduction in truck rolls across SGIG utilities saved an estimated 15,160 tons of carbon dioxide equivalent emissions from April 2011 to March 2015.[8] On average, a utility saved about 1.3 vehicle-miles traveled every six months for every smart meter deployed.

The Electric Power Board of Chattanooga (EPB) and NV Energy had full-scale AMI deployments and conducted wholesale conversions of manual processes to automated meter reading and remote service order fulfillment—resulting in significant O&M cost savings. NV Energy also has a highly transient customer base that historically has required relatively frequent requests for service connections and disconnections.

→ See **Case Study:** Electric Power Board (page 38)

Larger smart meter deployments generally resulted in higher O&M cost savings from smart meter automation. However, utilities with low customer densities and geographically dispersed service territories have greater savings potential than those located in densely populated urban areas. In addition, utilities that replaced electro-mechanical meters with AMI generally had higher incremental cost savings than those who replaced automated meter reading (AMR) with AMI. The average per-meter operations and maintenance cost savings was $8.37 over a six-month period in 2014 for 19 SGIG projects—though actual savings vary highly by project.

From 2011-2014, 19 projects reported a cumulative O&M cost savings of more than $316 million, resulting in an average of $16.6 million savings per project over three years. However, the range of actual per-project savings was quite large; three of the projects realized the majority of the total savings, with more than $174 million saved by one project alone.

→ See **Case Study:** CenterPoint Energy (page 38)

CenterPoint Energy, for example, reported AMI cost savings of more than $61 million from 2012-2014. Tri-State Electric Membership Corporation realized a 65 percent decrease in annual meter operations costs from a high of about $450,000 per year in 2011, to about $156,000 per year in 2013.

→ See **Case Study**: Tri-State Electric Membership Corporation (page 44)

Key Result: Improved Accuracy and Customer Services

AMI and related systems can dramatically reduce and help quickly address customer complaints by empowering customers and utility service representatives with access to accurate, timely, on-demand information about customer consumption and costs.

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[6] Cumulative data from 42 projects reporting

[7] Cumulative data from 21 projects reporting.

[8] Based on analysis of vehicle operations data from 31 SGIG projects.

AMI-enabled bill generation results in fewer customer complaints about inaccurate bills and enables utilities to resolve billing disputes faster than before. Several SGIG projects report improvements in bill dispute resolution rates, because customer service representatives can now access real-time and historical energy use information to field customer questions. AMI improves the accuracy of meter readings by automating activities previously accomplished manually, minimizing human and other errors. For example, hand-held reads are subject to probe failures, manual keying errors, meter memory failures, and wiring issues that can cause low reads. With AMI, utilities no longer have to estimate or interpolate bills, or offer bill adjustments, due to meter reading errors or missed readings.

→ See **Case Study:** Oklahoma Gas and Electric (page 30)

Access to detailed information on consumption and costs using IHDs or web portals, and the availability of this information at any time of day or night, helped customers to self-diagnose causes of high electricity bills and develop strategies for better managing consumption and costs without needing to contact utility customer service representatives. Utility customer service representatives can retrieve customer billing details instantaneously and are better able to find causes and suggest energy efficiency solutions or alternative rate options.

AMI enables utilities to proactively address customer billing issues. When appropriately programmed, CIS can prompt utility customer service representatives to preemptively contact customers about unusual usage patterns in advance of the bill being sent. Effective training of customer service personnel is paramount for using the enhanced information and implementing advanced billing and complaint-reducing features. AMI enabled unique proactive problem solving:

→ See **Case Study**: Burbank Water and Power (page 58)

- South Norwalk Electric and Water—a member of Connecticut Municipal Electric Energy Cooperative (CMEEC)—uses the service connect/disconnect switch to show customers in multi-dwelling buildings that the meter for which they are being billed is the correct meter for their account. This test can be performed remotely without a meter technician on site.
- Before AMI, Raft River Rural Electric Cooperative in Idaho, a member of the Pacific Northwest Generating Cooperative (PNGC), would disconnect all irrigation accounts in the fall, and then leverage seasonal charges in the spring. With AMI, Raft now tracks irrigation accounts, and automatically determines when they are operating and if bills need to be sent. This reduces operating costs for truck rolls and labor.

Utilities with AMI are now able to fulfill remote service connection and disconnection orders in hours instead of days. Before AMI, customers waited several days for the utility to address service requests. Typical of many SGIG projects, Central Maine Power (CMP) reports now being able to fulfill reconnection service orders remotely in under 7 minutes.

→ See **Case Study:** Electric Power Board (page 38)

2.2 Online Bill Payments and Pre-Pay Billing Plans

Online bill payment provides customer convenience while eliminating traditional paper payment processing costs, errors, and delays. Pre-pay billing programs reduce billing fluctuations, unanticipated high electric bills, and service disruptions for customers on pre-pay programs by communicating usage on regular intervals. In addition, unpaid bill write-offs for utilities were reduced.[9] Seven utilities offered pre-payment plans, which are used to help customers closely track their energy consumption and costs and help utilities to reduce the amount of unpaid bills.

Online bill payment capabilities are common in the electric power industry, but the implementation of web portals in connection with AMI deployments has enhanced customer insight. Greater customer use of this service reduces costs of paper bills and lowers error rates from processing paper payment slips and checks. Online bill payments require development of secure and user-friendly web portal interfaces for processing payment information. While AMI is not necessary to implement online bill payments, it can help streamline the process and results in fewer data entry errors.

Many utilities have developed mobile phone applications for customers to access billing information, receive usage alerts, submit payments, and report outages. Because mobile phone networks generally remain in service during power outages, the outage reporting feature is useful for timely reporting of outages without over-burdening customer service representatives.

Key Result: Enhanced Revenues and Reduced Bad Debt Write-Offs

Several utilities improved revenue collection and cost recovery by implementing pre-pay billing programs that help customers avoid defaulting on their bills.

Pre-pay billing plans contributed to a reduction in bad debt write-offs[10] and allowed participating customers to budget electricity use. Reducing debt write-offs improves revenue collection, which strengthens cost recovery and improves the financial health of the utility. These improvements ultimately benefit customers because utilities are better able to manage operating costs.

→ See **Case Study**: Talquin Electric Cooperative (page 40)

For utilities, pre-pay also reduced billing-related operational costs (because pre-pay is usually paperless) and reduced customer service complaints. In addition, services can be remotely disconnected or reconnected based on account balances, avoiding service calls and truck rolls.

Talquin Electric Cooperative (TEC) decreased its bad debt write-offs by about 65 percent since 2011 due in part to its pre-pay program offering. Tri-State Electric Membership Corporation's bad debt decreased from almost $46,000 in 2011 when the pre-pay program started to about $21,000 in 2013. Also, effective bad debt fell by 97 percent, from $44,000 to just over $1,000 between 2011 and 2013.

Pre-pay billing plans provide convenient services for customers needing assistance in managing consumption and costs. For customers, pre-pay plans reduce or eliminate service deposits, late fees, and

→ See **Case Study:** Sioux Valley Energy (page 60)

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[9] DOE, *Bridging the Gaps on Prepaid Utility Service*, September 2015.

[10] From an accounting perspective, bad debt write-offs are overdue utility bills that customers are not likely to pay.

reconnect fees; reduce post-paid billing surprises due to unexpected or high usage (e.g., high heating or cooling requirements); and can help track consumption and costs using web portals and automated alerts by email, text message, and phone call. Pre-pay plans also offer seasonal or temporary customers with an improved ability to obtain and manage electricity services.

2.3 Meter Tampering and Theft Detection

Historically, meter readers or headquarters personnel detected electricity theft by identifying abnormal changes in electricity usage over long periods. Customers have been known to go to great lengths to steal electricity, often breaking into or attempting to bypass meters. In many cases, people tampering with meters risk getting burned, electrocuted, or even killed. While only small numbers of customers are typically involved in meter tampering and electricity theft, Forbes reported in 2013 that electricity thefts amount to about $6 billion annually, which would make electricity the nation's "the third most stolen item, after credit card data and automobiles."[11]

SGIG funding recipients used AMI to program MDMS to detect instances of meter tampering, which indicated potential cases of electricity theft. Many utilities have systems that issue alarms or notifications when irregularities in consumption activity are identified. The SGIG utilities found that the tamper incidents in many instances were not always due to actual theft, but sometimes faulty meters.

Key Result: Enhanced Revenue Collection

New capabilities for tamper and theft detection through AMI deployments enhance revenue and cost recovery. Utilities are able to improve revenue collection and cost recovery from enhanced theft detection capabilities, identification of faulty meters, and registering previously unregistered (and therefore non-paying) meters. Additional benefits include labor hour savings, fewer truck rolls, and reduced time to find violators.

Utilities on average confirmed 951 tamper detections, with six utilities reporting more than 1,000 incidents and two utilities confirming more than 5,000 incidents (out of 29 projects reporting). One utility identified 600 improperly configured meters.

CenterPoint Energy boosted revenue collections by more than $4.5 million from 2012 to 2014 from the identification of slow meters, unregistered meters, and electricity theft.

→ See **Case Study:** CenterPoint Energy (page 38)

Tamper detection also created new technical challenges for several utilities who faced increased tamper detection costs when false alarms required field investigations. Several utilities are now working to develop better data analytics to differentiate actual theft incidents from the many different events that can trigger tamper alarms. Data analytics can be used to reduce the number of false positives and unnecessary truck rolls.

[11] Kelly-Detwiler, Peter, "Electricity Theft: A Bigger Issue Than You Think," *Forbes*, April 23, 2013.

2.4 Outage Detection and Management

AMI became an essential aspect of service restoration activities and OMS operations for the many SGIG projects that augmented their investments in DA implementing AMI. Smart meter data enabled these utilities to reduce the costs and boost the effectiveness of outage management operations. Smart meters with outage detection and notification automatically transmit a "last gasp" notification when power to the meter is lost. Smart meters enable automatic outage and restoration notification, which previously had to be verified by phone or service call. Last-gasp meter alerts enable grid operators to identify outage locations and dispatch repair crews to more precise locations where they are needed. The alert includes the meter number and a time stamp, which indicates the location of the meter and the time of the outage. Smart meters can also transmit "power on" notifications to the head-end systems or OMS when power is restored. This information can be used to more effectively manage service restoration efforts and help ensure that no other outages have occurred before repair crews are demobilized. Utilities can "ping" smart meters in outage-affected areas to assess outage boundaries and verify when power has been restored to specific customers.

AMI enables different—but complementary—outage management functions from those enabled by DA technologies.[12] AMI monitors outages at the customer meter to help utilities assess and characterize outage events, whereas DA technologies monitor outages at feeders and substations and, in some cases, help automate power restoration on feeders and substations. AMI and DA outage management functions combine effectively, particularly when AMI is integrated with DMS.[13]

Key Result: More Accurate Outage Location to Support Rapid Restoration

AMI enables utilities to identify outages more quickly and to dispatch repair more precisely, thus reducing the duration of outages and producing lower outage costs and fewer inconveniences for customers. In addition, remote meter queries shorten service restoration times by identifying "nested" outages—an electrical problem that is "masked" by a larger outage. In these situations, which generally follow severe weather events, repair crews fix obvious problems and believe power has been restored to an entire area. Before AMI, repair crews would normally leave at this point, unaware of the secondary electrical problem until customers affected by the nested outage call to complain. Remote meter query can avoid the restoration delays associated with nested outage identification.

→ See **Case Study**: Central Lincoln Peoples Utility District (page 42)

AMI reduces labor hours and truck rolls associated with outage diagnosis and restoration. In the past, customers called a hotline to notify the utility of an outage. Once the repair was made, the utility assumed all customers on the feeder had their power restored. In large-scale outages, this is often an incorrect assumption, leading to further

→ See **Case Study**: Tri-State Electric Membership Corporation (page 44)

[12] For final results from the SGIG distribution automation projects, see U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Grant Program*, 2016.

[13] Note that AMI-enabled functions could be integrated by the DA operations, but usually not vice versa.

customer calls and complaints. Because meter status can be checked without a truck roll, one utility avoided more than 300 "okay-on-arrival" truck rolls during one storm alone.

Utilities facing regular, severe weather events and storm-induced outages have greater incentives for using AMI for outage management. 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.

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.

Key Result: Improved Outage Information Sharing and Customer Notification

Once AMI data has been processed and integrated with CIS, OMS, and GIS, utility personnel have access to more accurate and timely data about outages and service restoration activities. New software tool and mapping capabilities boost overall situational awareness when outages occur, and enable utility officials to provide customers, first responders, local officials, and the news media with better information to improve customer satisfaction levels and coordination with government agencies and the public.

→ See **Case Study:** Electric Power Board (page 38)

Some utilities used GIS with smart meter data to create detailed outage maps, and in some cases posted these maps on utility websites to keep the public and local media informed with service restoration progress. Meter pinging enables operators to track progress and inform repair crews of customers still without power. All of these efforts measurably improved outage restoration processes and procedures, lowered costs, accelerated repairs, shortened outage durations, and reduced customer outage costs and inconveniences.

→ See **Case Study**: Burbank Water and Power (page 58)

2.5 Voltage Monitoring

Utilities can use AMI voltage monitoring capabilities to enhance the effectiveness of automated controls for voltage and reactive power management, particularly for conservation voltage reduction (CVR) programs. Voltage monitoring is the smart meter capability to measure voltage levels and certain power quality parameters, which utilities can use to develop accurate voltage profiles across feeder lines throughout the system. For example, smart meters can be used to measure current transients and harmonics; this feature is most often activated for industrial customers who operate sensitive machinery, motors, and rotating equipment. Data on voltages can be used to diagnose customer voltage issues remotely and determine if the issue is related to the distribution system or is the result of factors occurring inside customer premises. Voltage data is processed by the DMS and can be used by grid operators to develop distribution system models and optimize voltages across the grid.

Key Result: Enhanced Voltage and Reactive Power Management

With smart meter voltage monitoring, grid operators can assess voltage conditions and ensure CVR operations maintain voltage levels within acceptable limits. Several SGIG projects successfully did this. Benefits from these practices include reduced line losses and peak demands, improvements in power factors, and energy savings. Voltage monitoring and controls provide utilities with another resource option for managing grid operations, controlling costs, and maintaining adequate supply-demand balances.

→ See **Case Study**: Central Lincoln Peoples Utility District (page 42)

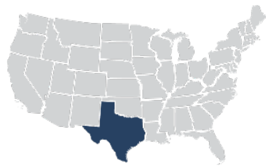
SGIG utilities testing voltage monitoring and reactive power management applications often used AMI capabilities in conjunction with DA technologies and systems. Project results specific to those DA technologies are reported separately and in greater detail in *Distribution Automation: Results from the SGIG Program*.

Voltage monitoring provides another useful benefit stream to include in business case analysis of AMI investments. Since it is used in conjunction with other smart grid technologies and systems, such as line sensors, voltage regulators, and automated capacitor banks, it can be difficult to estimate the incremental value of AMI in evaluating investments in automated controls for voltages and reactive power management. Utilities are developing tools for data analytics to support such analysis, which would not be possible without voltage data from AMI deployments on affected substations and feeders.

Voltage monitoring capabilities are available on smart meter deployments, but not all utilities are currently using them. Prior to the SGIG program, the business case for CVR using smart meters was not clear. Continued demonstration of CVR benefits by leading utilities and growing market adoption of DER is likely to drive utility interest in investments in voltage monitoring and control technologies and systems. Even if not used at the outset of AMI deployments, utilities can enable this capability when they are ready to move forward with automated controls for voltage and reactive power management.

CASE STUDY: **CENTERPOINT ENERGY**

Investor-Owned Utility



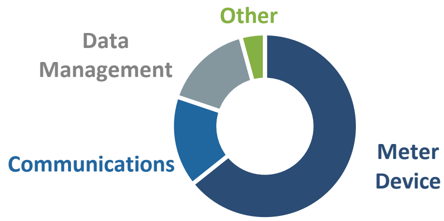
Houston, TX

2,320,256 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$514,519,057**

AMI Cost Breakdown



Total Number of Meters Installed: **2,130,737**

Average Cost per Meter: **$241**

Communication Type: Mesh Network

Backhaul Network: Wi-Fi WiMAX

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	100%
Outage Reporting	100%
Voltage Monitoring	0%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✓
Distribution Management System	✓

Customer Devices Installed	
In-Home Device	504

Customers Enrolled in New Programs	
Web Portal	18,798

AMI System and Communications: A combination of radio, microwave, and fiber optic technology support AMI. Using cellular signal boosters, WiMAX 3650-megahertz (MHz) radios, 900 MHz radios, and signal repeaters eliminated the need for more costly satellite services. In addition, the amalgamated network includes back-up cellular communications, back-up battery power, data security encryption, and advanced site designs for hard-to-reach areas. Two-way communications with AMI meters occurs via private radio network.

AMI Cost Savings: CenterPoint Energy reported AMI cost savings in a regulatory filing of more than $61 million from 2012-2014. Table 5 provides a breakdown of the cost savings. The availability of more detailed and timely data on peak electricity usage and distribution system conditions improves load forecasting and capital investment planning.

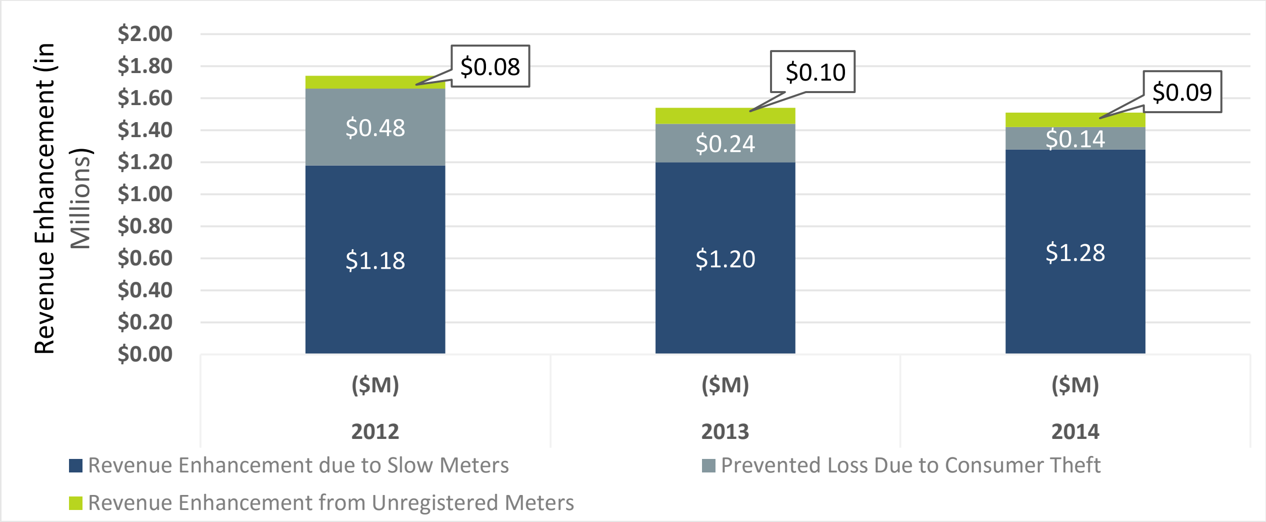
Fuel Savings and Reduced Service Order Fees: Cumulative fuel savings reached about 950,000 gallons as of August 31, 2014. CenterPoint Energy processed almost 10 million automated service orders from 2009-2014, saving customers approximately $24 million annually in service order fees.

Table 5. CenterPoint's Breakdown of AMI Cost Savings, 2012-2014

	2012	2013	2014
Meter Reading	$17,198,455	$17,946,205	$18,376,912
Route Design Personnel	$0	$150,512	$154,124
Electric Revenue Billing Personnel	$676,468	$1,360,024	$861,346
Injuries, Vehicle, and Other Claims	$300,755	$313,614	$321,141
Avoided Meter Reader Hires	$500,424	$885,808	$1,276,944
Miscellaneous Meter Rereads	$324,709	$338,591	$346,718
Workmen's Comp Insurance Premium	$12,083	$12,603	$12,906
Business Process Personnel	$0	$83,520	$85,524
Total Savings	**$19,012,894**	**$21,090,877**	**$21,435,615**

Enhanced Revenue Collection from Theft Detection: In 2012, prevented revenue losses from theft and faulty meters exceeded $450,000 and in 2014, the prevented revenue losses exceeded $130,000. CenterPoint Energy boosted revenue collections from identification of slow meters, unregistered meters, and electricity theft by more than $4.5 million from 2012 to 2014. Figure 9 provides a breakdown of these benefits.

Figure 9. Enhanced CenterPoint Energy Revenue Collections, 2012-2014



Reduced Peak Demand: CenterPoint's web portal provides smart meter customers information to help them better manage their energy usage and costs. CenterPoint Energy conducted customer education on steps to take to reduce peak demands, and provided prizes for successful responses. In 2011, 198 participants reduced peak demand by an average of 5 percent during 10 events, and some participants reduced consumption by as much as 35 percent.

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

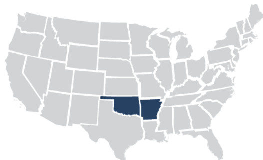
CenterPoint Energy Project Page

CenterPoint Energy Project Description – *September 2014*

CenterPoint Energy Case Study – *February 2012*

CASE STUDY: **OKLAHOMA GAS AND ELECTRIC (OG&E)**

Investor-Owned Utility



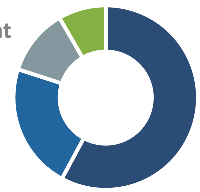
Oklahoma and Western Arkansas

843,914 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$277,716,012**

AMI Cost Breakdown



Total Number of Meters Installed: **818,415**

Average Cost per Meter: **$339**

Communication Type: Mesh Network

Backhaul Network: Wi-Fi WiMAX

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	90%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✗
Distribution Management System	✗

Customer Devices Installed		Customers Enrolled in New Programs	
Programmable Communicating Thermostat	28,668	Web Portal	61,097
		Time-of-Use Pricing	38,997
		Critical Peak Pricing	1,536
		Variable Peak Pricing	37,461

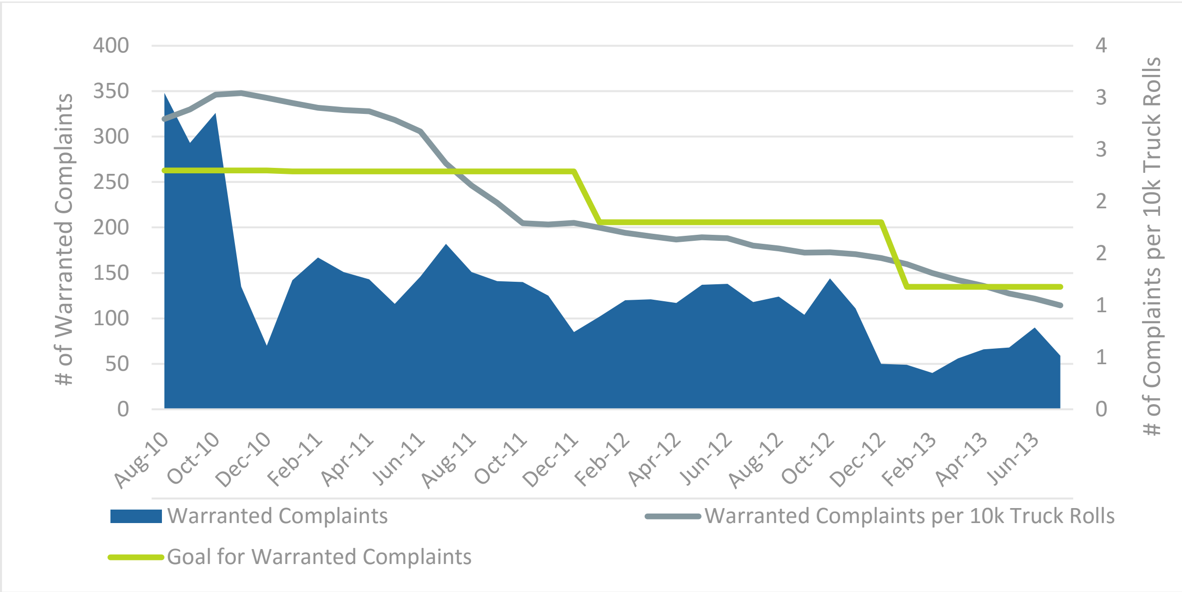
AMI System and Communications: A secure wireless mesh AMI network enables two-way meter communications, provides the backbone for energy management programs, and allows for integration with smart appliances and home area networks. OG&E also installed a WiMAX point-to-multi-point Wide Area Network (WAN) that connects to a point-to-point microwave network for backhaul communications. The project has deployed 818,415 smart meters covering OG&E's entire service territory and supporting information technology infrastructure, including a MDMS.

O&M Cost Savings: Oklahoma Gas and Electric (OG&E) reports saving almost $36 million total in cumulative meter operations costs from April 2012 to March 2015—about $9 million per year. These savings reflect the transition of meter readers to higher-value services, as well as reductions in truck tolls and vehicle-miles traveled. OG&E reduced about 180 legacy meter operations positions due to operational efficiency gains from AMI.

Reduced Truck Rolls: OG&E avoided 1,318,455 meter operations truck rolls between 2012 and 2014. By the end of 2012, OG&E had fulfilled more than 475,000 connect/disconnect requests remotely.

Reduced Customer Complaints from Improved Service: Figure 10 shows the decrease in the number of warranted customer complaints from August 2010 to June 2013 at OG&E from improved meter operations. The data include both total values and 12-month rolling averages.

Figure 10. OG&E Customer Complaints, 2010-2013.



Reduced Peak Demand and Improved Capital Investment Planning: OG&E conducted a VPP pricing pilot program, as part of the SGIG CBS, involving 4,000 residences and 1,320 small businesses, including the control group. It consisted of a multi-tiered rate with four defined price levels: Low ($0.05 per kilowatt-hour), Standard ($0.092 per kilowatt-hour), High ($0.218 per kilowatt-hour), and Critical ($0.458 per kilowatt-hour). Peak hours were 2 p.m. to 7 p.m. on weekdays, and prices during peak periods varied from Low to Critical based on temperatures and system conditions. Participants were notified of price changes on a day-ahead basis, with the exception of critical price events, which had a minimum two-hour notice. More detailed and timely data on peak electricity usage improve load forecasting and capital investment planning.

The pilot program gave OG&E the ability to reduce load by 70 megawatts (MW). This early success is driving OG&E to roll out the rate to about 20 percent of its customers (120,000 residential customers), offering a free PCT to each customer, with the aim of deferring investment in about 170 MW of power plant capacity. OG&E's pilot rate offers with PCTs were more cost-effective for the utility than those without PCTs.

Customer Savings from Pricing Programs: In 2012, OG&E recorded an average annual savings of $191.78 for residential customers and $570.02 for commercial customers participating in OG&E's pricing programs; 99 percent of participating customers saved money through the program.

READ MORE ABOUT OKLAHOMA GAS AND ELECTRIC PROJECT ON SMARTGRID.GOV:

Oklahoma Gas and Electric Project Page

Oklahoma Gas and Electric Project Description – *September 2014*

Oklahoma Gas and Electric Case Study – *May 2011*

CASE STUDY: **CENTRAL MAINE POWER (CMP)**

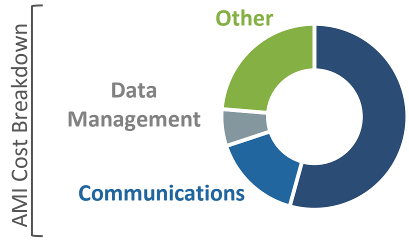
Investor-Owned Utility

Maine

622,380 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$180,474,628**



Total Number of Meters Installed: **622,380**

Average Cost per Meter: **$290**

Communication Type: Mesh Network

Backhaul Network: Ethernet Cable DSL

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	93%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Operations Management System	✓
Distribution Management System	✗

Customers Enrolled in New Programs	
Web Portal	26,521

AMI System and Communications: Central Maine Power (CMP) deployed a high-bandwidth radio frequency wireless mesh network that provides two-way communications utilizing a combination of multiprotocol label switching (MPLS), digital subscriber line (DSL), and cellular backhaul between smart meters and CMP's back office systems. The high-bandwidth wireless network supports distribution automation devices as well as metering data.

Meter Operations Cost Savings: CMP reports saving more than $7 million in meter operations costs in 2013 from AMI deployment. The utility achieved cash flow savings of almost $180,000 (in 2011-2013) by reducing the time between reading and billing.

Fewer Truck Rolls and Vehicle Miles: CMP avoided over 300,000 truck rolls in 2012, amounting to roughly 1.7 million avoided vehicle miles, due to AMI deployment. CMP fulfills about 2,000 service orders remotely every day, which represent more than 95 percent of all of its service orders. CMP re-assigned one billing position due to new AMI business processes, and saw a reduction in call volumes that helped it achieve efficiencies in its call center.

Improved Bill Accuracy, Tamper Detection, and Fewer Customer Disputes: CMP saw a reduction in the number of estimated meter readings from 95,441 in 2010 to 5,833 in 2012. At CMP, the number of customer calls to dispute bills, including estimated bills, decreased 29 percent following AMI deployment, from 3,789 in 2010 to 2,696 in 2012. Using tamper detection analysis, CMP identified 600 improperly configured meters and was able to make corrections and send accurate bills to customers.

Faster Remote Service Connection and Disconnection: Before AMI, customers waited several days for the utility to address service requests. Typical of many SGIG projects, CMP reports now being able to fulfill reconnection service orders remotely in under 7 minutes. After-hours reconnection services can be done automatically, and can be scheduled by the hour. Therefore, customers can request final meter readings off-cycle, on a certain day or a certain hour, including weekends. If customers pay their bill online over the weekend, service can be reconnected before Monday.

Improved Outage Management: CMP uses AMI data to help assess storm impacts and improve efficiencies in call center operations and field crew restoration efforts. The OMS is integrated with AMI systems and displays "on" and "off" meter status for faster outage assessment. Customer representatives ping customers meters to help determine outage restoration status.

Proactive Electricity Usage Alerts Improve Customer Response: CMP had more than 3,200 customers enrolled to receive weekly updates by email, text message, or phone call with billing information on their electricity use and cost. About 70% of the participants said they took actions to reduce their usage after receiving bill alerts, and participants reduced their annual electricity usage by 1.8 percent. Table 6 shows customer preferences for bill alert notification methods. For CMP's customers, email was the most preferred method by far.

Table 6: CMP Customer Preferences for Bill Alert Notification

Notification Preference	Enrollment Channel			Overall
	Email (N = 1,487)	Telemarketing (N = 1,621)	Direct Mail (N = 129)	
Email Only	84.1%	57.8%	79.1%	70.7%
Telephone Only	0.3%	30.4%	10.1%	15.7%
Text Message Only	5.6%	9.9%	8.5%	7.9%
Email & Text Message	9.3%	1.6%	2.3%	5.2%
Telephone & Email &/or Text Message	0.6%	0.4%	0.0%	0.5%
Total	**100%**	**100%**	**100%**	**100%**

Network Integration Challenges Produced Useful Lessons Learned: CMP faced technical challenges in integrating network equipment in its challenging terrain, which is hilly and includes many heavily-forested areas. It often involved vendors implementing network redesigns and making multiple modifications. Extensive regression testing was required for each system change. Because other utilities may not have this skill set in-house, CMP recommends third-party support in network system design. CMP also recommends installing network-monitoring tools before the integration of communications networks, and scheduling time for technical assessments and approvals before starting operations.

CMP formed a user group with other utilities to share information about problems and solutions and provide guidance for specifications to vendors. CMP found it helpful to share project goals with vendors because it helped keep implementation tasks and milestones in alignment with the project's overall aims.

Rigorous Meter Testing and Workforce Support: Central Maine Power (CMP) found that the need for frequent upgrades presented challenges for minimizing disruptions to customers, which meant that more rigorous meter testing was required than anticipated. CMP developed a testing protocol involving more than 50 meters located in the field. After researching the experiences of other utilities, CMP performed a bottom-up assessment of the tasks and skillsets required to support AMI deployments and operations. This effort assisted workforce management and helped guide the transition of the metering department to the new AMI system.

CMP initially focused its AMI deployment on improving operational efficiencies. Going forward, CMP plans to develop information systems and visualization tools for improving customer services and demand-side solutions with better data analytics.

READ MORE ABOUT CENTRAL MAINE POWER PROJECT ON SMARTGRID.GOV:

Central Maine Power Project Page

Central Maine Power Project Description – *May 2015*

Smart Meter Investments Yield Positive Results in Maine – *December 2013*

CASE STUDY: **POTOMAC ELECTRIC POWER COMPANY (PEPCO) – DISTRICT OF COLUMBIA**

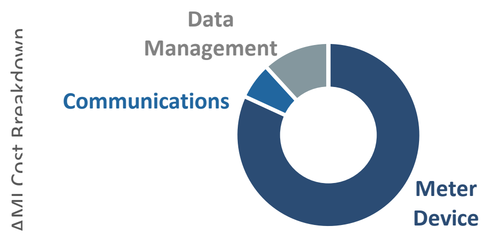
Investor-Owned Utility

Washington, DC

277,222 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG:
$71,661,658



Total Number of Meters Installed:
277,222

Average Cost per Meter:
$258.50

Communication Type: Wireless Mesh

Backhaul Network: Cellular

Enabled Features on Percent of Smart Meters		AMI Integrated with:	
Remote Connect/Disconnect	96%	Billing System	✗
Outage Reporting	97%	Customer Information System	✓
Voltage Monitoring	97%	Outage Management System	✓
Tamper Detection	97%	Distribution Management System	✗

Customer Devices Installed		Customers Enrolled in New Programs	
Direct Load Control	16,010	Web Portal	14,093
Programmable Communicating Thermostat	11,383		

AMI System and Communications: Pepco installed a wireless mesh network for the AMI system and designed it to be able to route DA traffic through the battery-backed wireless communications devices. This approach ensures that DA traffic remains on energized communications devices during power outages. The same backhaul cellular network is used to transport AMI and DA data to the appropriate collection systems.

AMI Cost Savings: Pepco in Washington, DC reported AMI cost savings of more than $2 million in 2012, at a time when smart meter deployments were not yet fully implemented. Table 7 provides a breakdown of these savings.

Table 7. Pepco DC AMI Cost Savings for 2012

Cost Category	AMI Cost Savings (thousands of dollars)
On-cycle meter reading	$924
Improved billing processes	$189
Off-cycle meter reading	$343
Truck roll reduction	$680
Improved complaint management	$79
TOTAL	**$2,215**

Reduced Customer Outages and Proactive Transformer Replacement: During 2013, AMI technologies helped Pepco prevent over 6,000 customer outages. Pepco has also begun to use AMI data for transformer load management. The accuracy of transformer loading data allows for a more proactive replacement under a planned outage strategy (as opposed to the prior practice of waiting for transformer over-loading, leading to asset failure). Transformer replacement under a planned outage results in a lower outage duration than that associated with emergency repairs.

Customer Savings and Bill Credits: Through 2013, Pepco operated 4 curtailment events, reducing demand by 15 megawatts. Participating customers received a total of $1,671,931 in bill credit incentives, and each participating customer had a web-programmable thermostat or outdoor direct load control switch installed on their home. The web portal allows customers to view the data collected from their smart meters and obtain information about the amount, timing, and costs of electricity usage. The web portal also provides the platform for customers to view and control the PCTs.

READ MORE ABOUT PEPCO – DISTRICT OF COLUMBIA PROJECT ON SMARTGRID.GOV:

PEPCO – District of Columbia Project Page

PEPCO – District of Columbia Project Description – *September 2015*

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

Municipal/Public Utility

Chattanooga, TN; Georgia

175,116 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG:
$179,170,347

AMI Cost Breakdown

Total Number of Meters Installed:
175,116

Average Cost per Meter:
$1,023

Communication Type: Fiber

Backhaul Network: Fiber

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	0%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	0%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✓
Distribution Management System	✗

Customers Enrolled in New Programs	
Web Portal	139,478
Time-of-Use Pricing	130

AMI System and Communications: The Electric Power Board (EPB) deployed a fiber optic network enabling two-way communication and data transfer for a new AMI system and DA equipment on over half of EPB's circuits. The project also delivered time-based rate programs to customers to create incentives for peak load and overall bill reductions. This infrastructure provided EPB with expanded capabilities and functionality to optimize energy delivery, system reliability, and customer service options, including an energy management web portal.

O&M Savings: EPB realized $1.6 million in annual operational cost savings through automation of meter reading—one of the largest AMI O&M savings recorded in the SGIG projects. EPB's full-scale AMI deployments included the wholesale conversion of manual processes to automated meter reading and remote service order fulfillment. EPB lowered operations costs from remote meter reading and improved identification of electricity theft.

Effective Systems Integration Planning: EPB also evaluated water heater load control devices that required integration with existing systems to work effectively. EPB conducted several internal requirements workshops to design the integration between the CIS, MDMS, and the Distributed Energy Resources Management System (DERMS). In addition, EPB extended the integration design to include the field installation of devices through its Computer Aided Dispatching system.

EPB's electric distribution system, which is over 60 years old, was designed with 115 small substations and limited centralized communications architecture. With a 600-square-mile territory and extreme annual storms, this lack of connected communications and distribution management capabilities has traditionally meant slow response times and labor-intensive outage recovery. With the addition of AMI and DA, EPB has turned an antiquated system design into a modern, automated, integrated grid with built-in redundancies.

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

Electric Power Board of Chattanooga Project Page

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

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

CASE STUDY: **TALQUIN ELECTRIC COOPERATIVE (TEC)**

Electric Cooperative

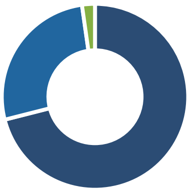
Northern Florida

56,000 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$15,245,056**

AMI Cost Breakdown



Total Number of Meters Installed: **54,945**

Average Cost per Meter: **$277**

Communication Type: Wireless RF

Backhaul Network: Microwave

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	100%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✓
Distribution Management System	✗

Customer Devices Installed	
Programmable Communicating Thermostat	1,000

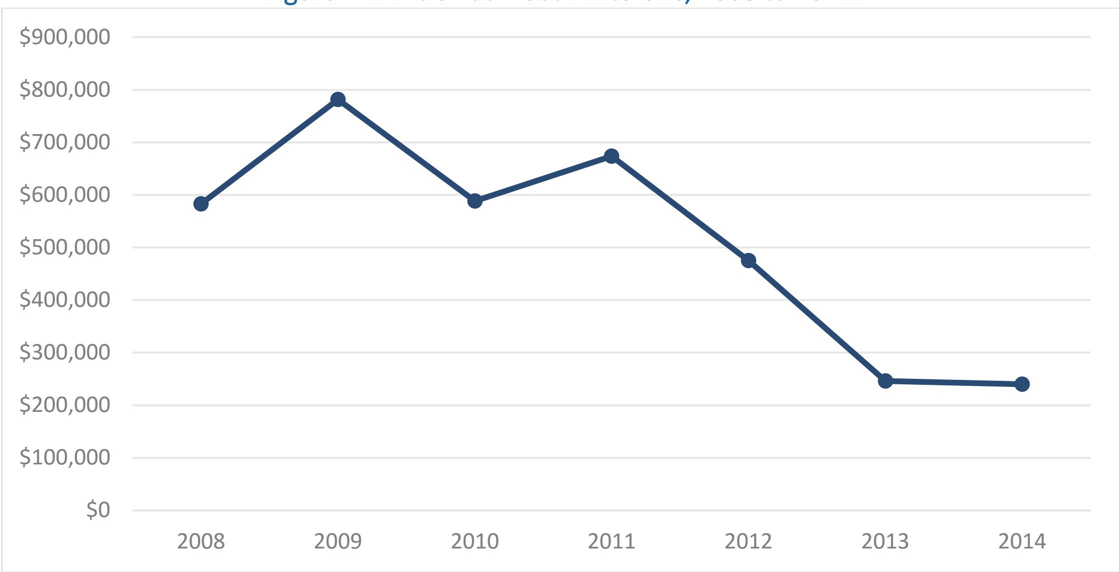
Customers Enrolled in New Programs	
Web Portal	18,000

AMI System and Communications: TEC overhauled its microwave communications infrastructure as part of its SGIG project. TEC's legacy microwave communications infrastructure did not have the bandwidth, redundancy, and storm resiliency required to support the new AMI system. To meet these needs, TEC installed a new primary microwave system, which was designed for 99.999 percent reliability and sufficient capacity to support future smart grid deployments.

Reduced Revenue Shortfall from Prior Manual Meter Reads: TEC had been billing customers since its inception in 1940 based on customers reading their own meters and reporting monthly consumption by writing the meter reading on the portion of the bill returned with payment, or by phoning the meter reading to TEC's offices. Because of inherent inaccuracies associated with this approach, TEC wrote off hundreds of thousands of dollars in revenue shortfall from misreporting, at levels far in excess of industry averages. TEC's AMI investments have eliminated these issues, and have opened new opportunities for further operational improvements and customer service enhancements. TEC reduced its annual meter operations costs by more than $568,000.

Reduced Bad Debt Write-Offs: TEC decreased its bad debt write-offs from unpaid customer bills by about 65 percent since 2011 due in part to its pre-pay program offering, as shown in Figure 11. Typical pre-pay programs allow payments to be split between existing balances and future use. From an accounting perspective, bad debt write-offs are overdue utility bills that customers are not likely to pay.

Figure 11. TEC's Bad Debt Write-offs, 2008 to 2014.



READ MORE ABOUT TALQUIN ELECTRIC COOPERATIVE PROJECT ON SMARTGRID.GOV:

Talquin Electric Cooperative Project Page

Talquin Electric Cooperative Project Description – *June 2015*

Talquin Electric Cooperative Case Study – *March 2012*

CASE STUDY: **CENTRAL LINCOLN PEOPLES UTILITY DISTRICT**

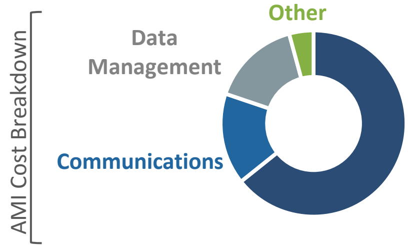
Municipal/Public Utility

Oregon

38,620 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG:
$16,290,554



Total Number of Meters Installed:
38,620

Average Cost per Meter:
$422

Communication Type: RF Mesh

Backhaul Network: Fiber Optic

Enabled Features on Percent of Smart Meters		AMI Integrated with:	
Remote Connect/Disconnect	97%	Billing System	✓
Outage Reporting	100%	Customer Information System	✓
Voltage Monitoring	100%	Outage Management System	✓
Tamper Detection	100%	Distribution Management System	✗

Customer Devices Installed		Customers Enrolled in New Programs	
In-Home Device	46	Web Portal	1,345

AMI System and Communications: A combination radio frequency (RF) mesh and fiber optic cable network connects the system wide deployment of smart meters. The network provides the necessary communications infrastructure to enable smart grid features such as AMI portal-based customer energy management tools and time-based pricing programs. Additional fiber was deployed to connect all substations to the control center. DA devices communicate with the substations via a high-speed wireless connection.

On-Demand Reading and Remote Services: AMI has changed completely how Central Lincoln Peoples Utility District in Oregon serves its customers. Since billing reads are received daily instead of once a month, customers are now able to select their own billing dates. With easier access to daily meter reads, customer service representatives are now able to perform on-demand reads, and open or close accounts immediately upon a customer's request. Service can be started or stopped remotely with the push of a button, rather than requiring customers to visit an office or the utility to dispatch a vehicle for a service call.

Fewer Truck Rolls and Reduced Meter Operations Costs: Central Lincoln reported a 50 percent reduction in meter operations costs in the first year following AMI installation, and reduced truck rolls relating to billing reads and connect/disconnects by 85 percent following AMI deployment.

Improved Outage Detection and System Integration: All Central Lincoln AMI meters are GPS enabled, allowing operators to see the exact location of a customer's outage using meter data. Sometimes trucks are rolled before customers call to say they are without power, and service is restored before customers who were not at home even discovered they had lost power. The utility recommends developing a meter numbering system that includes establishing GPS locations for all meter locations. This step helps meter deployments but also makes integrations with OMS and GIS easier to accomplish.

AMI for Voltage Monitoring and CVR: Central Lincoln uses AMI data to monitor end-of-line voltages. Operators sampled voltage data for a subset of customers every 15 minutes on a substation involved in a CVR pilot program. From these readings, operators calculate minimum voltages and the average of the lowest ten meters (known as the low average indicator). If these voltages are outside the target voltage band, operators raise or lower voltage set points on load tap changers in the substation. This pilot resulted in 2 percent energy savings for all customers. Based on these results, Central Lincoln plans to implement the CVR program system-wide.

Customer Access to Web Portal: Customers can monitor and manage their energy usage through the web portal, which is accessible via home computer or mobile devices. Energy usage is presented by year, month, week, day, and 15-minute intervals and overlaid with daily temperature. Customers can compare their energy usage to others with similar home characteristics, challenge themselves to save energy, and receive alerts when they are using more electricity than usual.

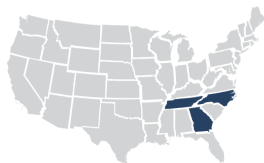
READ MORE ABOUT CENTRAL LINCOLN PEOPLES UTILITY DISTRICT PROJECT ON SMARTGRID.GOV:

Central Lincoln Peoples Utility District Project Page

Central Lincoln Peoples Utility District Project Description – *August 2014*

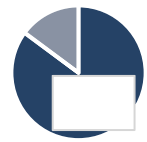
CASE STUDY: **TRI-STATE ELECTRIC MEMBERSHIP CORPORATION**

Electric Cooperative



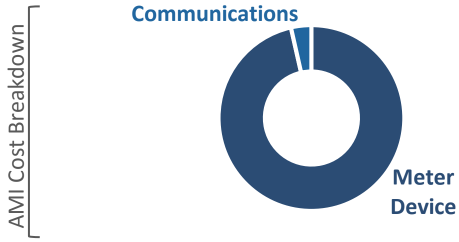
North Carolina, Georgia, Kentucky

17,802 Customers



Partial Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$2,412,394**



Total Number of Meters Installed: **15,156**

Average Cost per Meter: **$159**

Communication Type: Power Line Carrier

Backhaul Network: Fiber

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	14%
Outage Reporting	0%
Voltage Monitoring	0%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✗
Outage Management System	✗
Distribution Management System	✗

Customers Enrolled in New Programs	
Web Portal	947
Pre-Pay	810

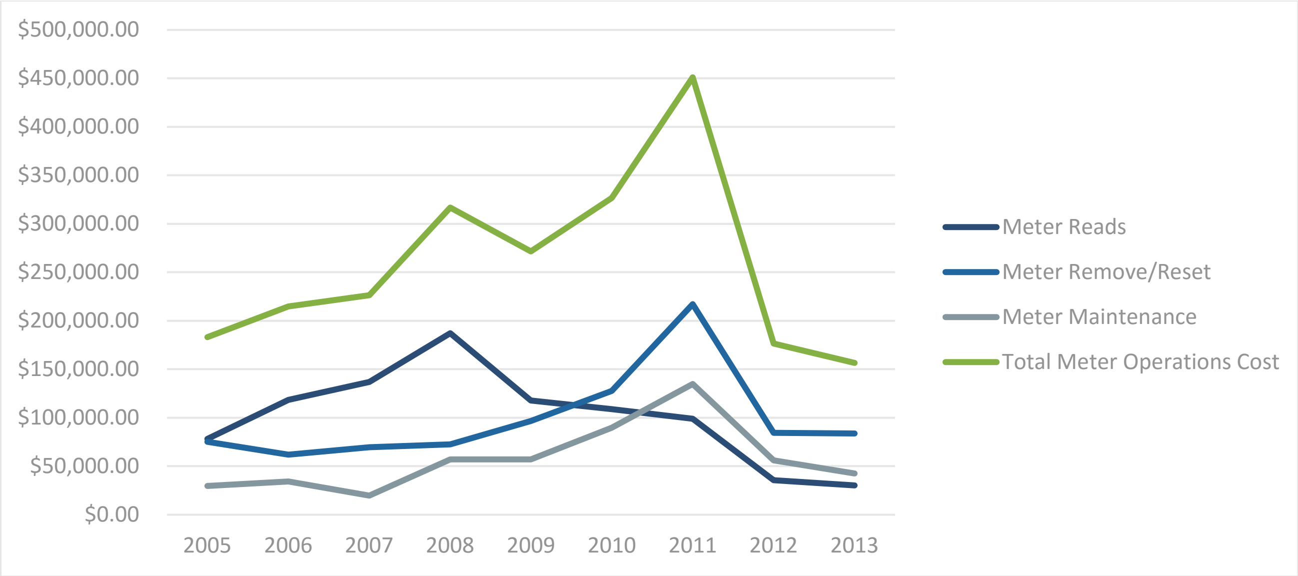
AMI System and Communications: Power line carrier communications modules relay data from smart meters, through substations, to Tri-State's back office monitoring systems. The power line carrier decision was driven by the utility's hilly geographical profile and low customer density, which make the business case for a wireless approach less financially attractive. An upgraded meter data management system (MDMS) provides a platform for validation, organization, analysis, and distribution of the meter data to other applications, including the billing system and the new customer web portal.

Reduced Truck Rolls and Vehicle Miles: Tri-State avoided 13,000 truck rolls in the first two years following the deployment of 2,000 remote service switches on AMI meters, avoiding more than 51,800 vehicle-miles traveled.

O&M Cost Savings and Improved Reliability: Tri-State realized a 65 percent decrease in annual meter operations costs from a high of about $450,000 per year in 2011, to about $156,000 per year in 2013. Tri-State's SGIG AMI deployments began in 2010. Figure 12 provides a cost breakdown. Tri-State's smart meters allow the utility to reconnect service without being notified by customers, detect outages in subdivisions with many vacant second homes, and prevent potential property damages such as frozen pipes that can burst from lack of heat.

Operational savings, along with DOE co-funding under the SGIG program, contributed to a payback period of less than five years for Tri-State's entire smart metering investment.

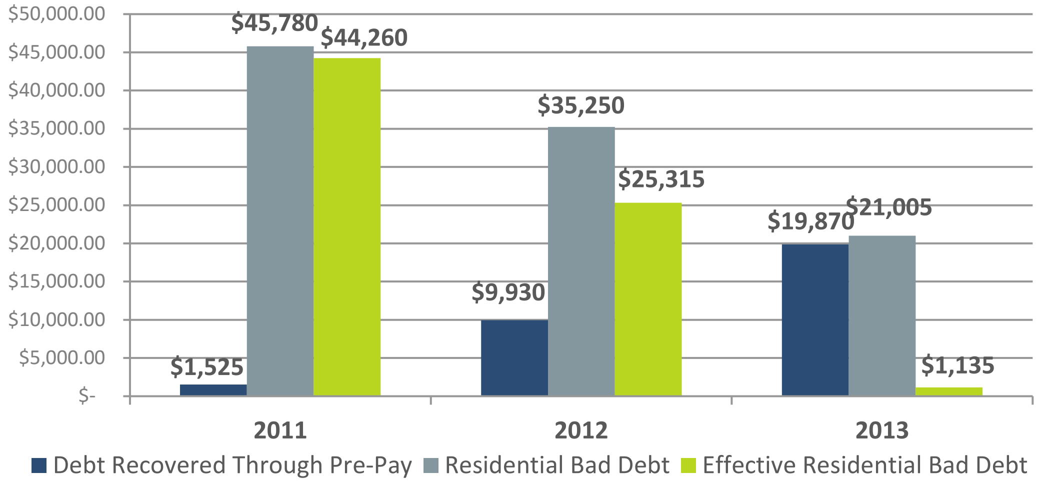
Figure 12. Annual Tri-State Meter Department Costs, 2005 to 2013



Reduced Bad Debt through Pre-Pay Program: Tri-State's voluntary pre-pay plan has been a popular option with some customers in part because no deposit is required and there are no late fees (as the account always has a credit). Deposits for traditional accounts normally range from $100 to $300, and late fees are typically 5 percent of the balance due after the due date. With pre-pay, customers can establish service for $75, including $50 of credits for future consumption. With the ability to disconnect service for zero-balance accounts and reconnect service immediately following payment (with no wait or fees), Tri-State has effectively eliminated write-off risks because the account holders must maintain a credit to keep service active.

Tri-State's bad debt decreased from almost $46,000 in 2011 to about $21,000 in 2013. Effective bad debt fell by 97 percent, from $44,000 in 2011 to just over $1,000 in 2013. Figure 13 shows Tri-State's bad debt recovery levels from 2011-2013.

Figure 13. Bad Debt Recovery from Tri-State's Pre-Pay Program, 2011-2013.



Web Portal Data Diagnoses High Bills and Helps Monitor Vacant Homes: Tri-State encourages customers to use the web portal to diagnose high bill issues. Customer service representatives also use the web portal as a tool to explain high bills and discuss possible causes such as weather conditions, changes in behavior or occupancy, or potential problems with heating and cooling equipment. Tri-State can set alerts for high consumption and send customers emails to warn about potentially high bills. In one case, usage monitoring alerted an out-of-town customer to a home break-in and theft because doors and windows were left open and electric usage increased.

Tri-State Electric Membership Corporation plans to offer new time-of-use (TOU) rates to its customers, in conjunction with web portal access, to manage peak demand.

READ MORE ABOUT TRI-STATE ELECTRIC MEMBERSHIP CORPORATION PROJECT ON SMARTGRID.GOV:

Tri-State Electric Membership Corporation Project Page

Tri-State Electric Membership Corporation Project Description – *July 2014*

Tri-State Electric Membership Corporation Case Study – *September 2011*

Smart Meter Investments Benefit Rural Customers in Three Southern States – *February 2014*

3 Major Customer System Findings: New Rates and Demand-Side Management Capabilities

The emergence of AMI enabled the use of a new class of customer devices and systems that operate using smart meter load data and price signals from the utility to facilitate customer participation in electricity markets and encourage peak demand reduction. Using customer systems in concert with AMI upgrades, SGIG utilities were able to pilot new time-based rate and incentive programs with more than 400,000 customers, demonstrate the integration of distributed energy resources, and conduct electric vehicle charging demonstrations.

The ability to communicate electricity prices and consumption levels frequently is an essential feature of the SGIG demand-side projects. AMI enables load data at intervals of 5 minutes to 1 hour to be transmitted to utility back office systems where it can be processed and sent to billing systems. While bills are typically sent out monthly, information on electricity consumption can now be made available to customers via web portals or other programs *the day after it has been collected* by the utility.

Green Button Initiative Improves Customer Data Access

The Green Button Initiative is an industry-led effort to develop a common technical standard and data format for customer usage information—which helps customers access and understand data, and helps software developers create innovative applications consumers can use to make the most of their data. Championed at the federal level by the White House, the National Institute of Standards and Technology (NIST), and DOE, the technical standard was developed in collaboration with NIST and the Smart Grid Interoperability Panel.

More than 60 million businesses and households are now served by utilities participating in the voluntary Green Button Initiative, including many involved in SGIG projects. There are almost 70 utilities, manufacturers, and government agencies participating in the Green Button Initiative, and 40 additional organizations are slated to join, further extending its reach to consumers.

3.1 Time-Based Rates and Direct Load Control

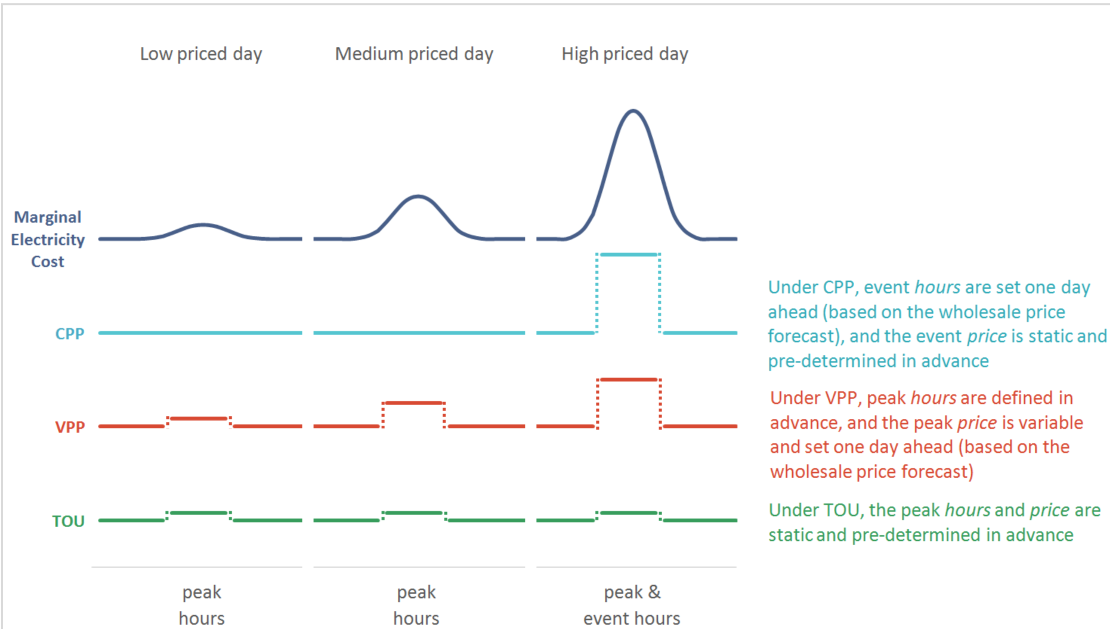
A total of 26 SGIG utilities piloted one or more time-based rates or incentive programs with a subset of their customers, and more than 417,000 customers participated in pilot rate programs under SGIG (see Table 8).

Table 8. Rate Types Offered by SGIG Pilots

Rate Type	SGIG Utilities Offering the Rate	Participating Customers Using the Rate
Time-of-Use Rate	18	63,360 customers
Critical Peak Pricing	9	7,862 customers
Critical Peak Rebates	7	308,924 customers
Variable Peak Pricing	1	37,461 customers

Time-based rates and incentive programs encourage customers to reduce electricity use during times of peak demand through price signals or rebates, with different prices offered at different times of the day or different days of the year. Figure 14 shows how different types of time-based rates—**critical peak pricing (CPP), variable peak pricing (VPP), and time-of-use (TOU) pricing**—can be used to reflect at an aggregate level the average of the marginal cost of producing electricity during various periods. Not shown in the figure is **critical peak rebates (CPR)**, an incentive-based program that offers bill reductions to customers who reduce peak demand on critical-peak event days compared to baseline levels.

Figure 14. An Illustration of Several Time-Based Rate Designs



To help customers take advantage of these new rates and incentive programs, SGIG utilities installed customer-based systems that give customers the information and tools needed to *actively* or *automatically* manage their electricity consumption and costs:

- **Information technologies—including IHDs, web portals, and text/email alerts—alert customers of peak events in advance, deliver price signals, and provide electricity consumption data to help customers *actively* reduce or shift their use.** Utilities typically delivered critical peak event alerts a day in advance through IHDs, cell phones, emails, web portal postings, and/or Twitter feeds. Customers with access to web portals could access their usage patterns by time of day to help determine how they could reduce their consumption during peak periods and examine their savings after an event.
- **Control technologies—such as PCTs and DLC switches—enable utilities and customers to *automatically* manage electricity consumption.** Customers can use PCT settings to automatically adjust heating and cooling temperatures in response to time-based rates. Utilities can send control signals to DLC devices to alter air conditioner and water heater cycling strategies, or turn on or off swimming pool and irrigation pumps.

Customers receive rebates or bill credits for participating in DLC programs. Utilities are typically limited in the number of hours per year they can adjust customer equipment, and many DLC programs allow customers to opt out of specific DLC events. DLC programs do not require AMI; hundreds of electric utilities have implemented DLC programs successfully since the 1950s.[14] While AMI can enhance DLC programs, very few utilities have tried to quantify these specific benefits, and DLC enhancements have not normally been included in a utility's AMI business case.

See the Consumer Behavior Studies for Further Results and Findings on Time-Based Rates

A subset of 10 SGIG utilities participated in Consumer Behavior Studies (CBS), which applied experimental designs and randomized samples to evaluate customer acceptance, retention, and demand response to various time-based rates, incentive programs, and customers systems such as IHDs and PCTs. The CBS projects were successful in accomplishing randomized assignments for treatment and control groups, enabling the utilities to produce more reliable statistical results on the impacts of time-based rates, customer information systems, and customer automated control systems on peak demand, electricity consumption, and customer bills.

This report includes only highlighted results. Please see the SGIG-CBS website for reports that include results and lessons learned from time-based rate programs under SGIG.

Key Result: Reduced Peak Demand and Overall Consumption

Time-based rate programs resulted in reduced peak demand for all projects, enabling some utilities to lower wholesale power purchase costs, sell excess electricity to regional markets, and defer investments in new generation and delivery capacity. In particular, the customers participating in time-based rate programs piloted by 10 utilities conducting CBS reduced their peak demand by up to 23.5 percent. Individual cost savings depended on the scale of the pilot, the rate type, and customer equipment.

→ See **Case Study:** Oklahoma Gas and Electric (page 30)

Several utilities found that offering PCTs that can automate customer response resulted in substantially higher peak demand reductions than programs that required active manual responses. Most utilities saw favorable cost-benefit ratios; for example, Oklahoma Gas and Electric decided to roll out a time-based rate with a free PCT to its entire residential customer class.

In contrast, IHDs had no measured effect on peak demand, and in many cases, participating customers declined to use them. Technical issues with their operations, including interoperability problems with smart meters, affected IHD effectiveness and in one case, the manufacturer decided to halt production and stop support. This decision reflected the relative immaturity of the market for customer systems at the time.

CPP and CPR effectively provide financial incentives for customers to reduce peak demand and customers typically remained enrolled for several years. With PCTs, customers enrolled in rate programs showed similar reductions in peak demand; without PCTs, CPP programs generally achieved greater reductions as compared to CPR programs. Several SGIG utilities planned system-wide deployments of these types of rates based on the results of their pilot-program evaluations.

[14] FERC, 2014 Assessment of Demand Response and Advanced Metering, December 2014.

One CBS study found that enrollment rates for opt-out recruitment strategies were about 3.5 times higher than they were for programs that required participants to opt-in (93% vs. 24%). Peak demand reductions were also generally larger under opt-in recruitment programs—twice as large in SMUD's CBS study. Retention rates were about the same for both approaches.

→ See **Case Study:** Sacramento Municipal Utility District (page 53)

→ See **Case Study**: Sioux Valley Energy (page 60)

Cost-effective time-based rate programs can often provide the tipping point for financially justifying AMI and customer system investments. The potential benefits of time-based rate programs depend on local power supply conditions, demand growth, and regulatory policies. Many states offer financial incentives for utilities to implement DSM measures, particularly energy-efficiency programs. AMI can help improve and expand rate program offerings, by providing detailed data on electricity use levels and patterns for impact analysis.

Key Result: Customer Bill Savings

By participating in DSM programs, customers can see financial benefits through bill savings and rebates, and gain greater control to manage consumption and costs. Information technologies and web portals helped customers learn about their patterns of electricity consumption and identify steps they can take to conserve electricity or shift their usage. Several of the SGIG projects measured customer bill savings from their rate programs over different time scales (see Table 9).

→ See **Case Study**: Burbank Water and Power (page 58)

Table 9. SGIG Examples of Customer Bill Savings from DSM Program Offerings.

Project	Bill Savings	Program Year(s)
Baltimore Gas and Electric	• **$9.08 average credit paid per customer** for four Energy Savings Days • **$2.8 million in bill savings** for all 700,000 participants in the Smart Energy Manager program	2013
Burbank Water and Power	• More than **$1 million in bill savings** for all 25,000 participants in TOU rate program across all program years	2011-2014
Green Mountain Power	• For customers on CPR and CPP, average savings across 14 peak events of **$2.52-$5.88** • Estimate a total annual bill reduction of **$50 per customer**	2012-2013
Oklahoma Gas and Electric	• Average annual savings of **$191.78 for residential customers** and **$570.02 for commercial customers** in its VPP pricing pilot program	2012
Sacramento Municipal Utility District	• Average summer bill savings **exceeding $77 on the TOU-CPP rate** for Summer Solutions participants • Average annual bill savings of just under **$40 per year** for customers who checked out an IHD	2012-2013

Customers who choose time-based rate programs may see bill increases, compared to standard rates, if they do not lower or shift their consumption during peak periods. Customers may only see bill savings if they made changes to shift consumption, or were already low consumers, during peak periods. For example, Sacramento Municipal Utility District (SMUD) found that while DLC pilot participants with TOU-CPP rates generally saved about 50 percent more than those with standard rates, some customers saw bill increases.

→ See **Case Study**: Sacramento Municipal Utility District (page 53)

3.2 Distributed Energy Resource and Electric Vehicle Integration

Several SGIG projects used new AMI capabilities to test out DER integration at a small scale and pilot electric vehicle (EV) charging programs to gain insight into the charging habits of EV drivers and their effect on the system. AMI provides accurate time-stamping of energy consumption information, which is vital for the integration of EVs and DERs such as rooftop solar and thermal energy storage systems. Both EVs and DERs could have potentially large impacts on the size and timing of electricity demand as the market for these technologies grow.

Key Result: Improved Integration and Billing for DERs and EV Charging

AMI plays a useful role in the customer adoption of DER by providing accurate information of on-site generation and storage usage, and on the amounts of excess generation delivered to local distribution grids through net metering mechanisms. In some cases, using AMI to sub-meter rooftop photovoltaic installations and energy storage units can boost accuracy and effectiveness of net metering at customer sites.[15] Fourteen projects used AMI to offer net metering rates—the rates customers with on-site generation are paid for selling their excess energy back to the grid—which are used to incentivize customer installation and ownership of distributed energy resources (DER).

Burbank Water and Power and Glendale Water and Power in California both integrated AMI with thermal energy storage systems for on-peak cooling of commercial and municipal buildings.

→ See **Case Study**: Glendale Water and Power (page 56)

Groton Utilities (GU), a member of the Connecticut Municipal Electric Energy Cooperative, is using AMI to record generation and usage, credit output, and billing for solar-assisted homes. GU provides two smart meters at each residential solar installation—one that records bi-directional power (from the utility system into the house, and excess power from the solar panels back out) and one that measures the total generation from the solar panels. This combination allows GU to provide a credit to the customer for generation back on to the GU system and a means for calculating total house usage, a requirement in GU's rate.

[15] U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Grant Program*, 2016.

Key Result: New Insights into Electric Vehicle Charging Patterns

SGIG AMI projects also examined how AMI services can support the integration of electric vehicle charging, and evaluated customer charging patterns under various rate options to help utilities anticipate how increased adoption of electric vehicles might affect peak and non-peak demand in the future. Though they represent a small portion of the more than 260 million U.S. passenger vehicles, electric vehicles are expected to grow from nearly 296,000 in 2014 to more than 2.7 million in 2023.[16] AMI investments contribute to the establishment of EV markets in several ways. Smart meters can be used to offer customers TOU rates for EVs to provide financial incentives for customers to charge vehicles during off-peak periods. The meters also provide valuable data for EV manufacturers and utilities on customer charging patterns, and to assess the grid impacts of different types of chargers, including standard (120 volts) and alternative chargers (240 and 480 volts). Looking to the future, AMI can contribute to advanced concepts like vehicle-to-grid applications where utilities can have access to EV storage capacity for meeting system needs.[17]

→ See **Case Study:** Sacramento Municipal Utility District (page 53)

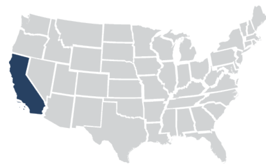
→ See **Case Study**: Glendale Water and Power (page 56)

Case studies for projects with EV programs are included in this report, and a full examination of lessons learned from the EV pilots is presented in *Evaluating Electric Vehicle Charging Impacts and Customer Behaviors*.

[16] Navigant Research, "Plug-in electric vehicles on roads in the United States will surpass 2.7 million by 2023," April 28, 2014.
[17] U.S. Department of Energy, *Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors*, November 2014; U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Grant Program*, 2016.

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

Municipal/Public Utility

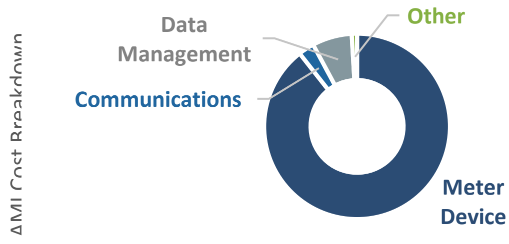


Sacramento, CA

672,860 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG:
$146,373,708



Total Number of Meters Installed:
617,502

Average Cost per Meter:
$237

Communication Type: Mesh Network

Backhaul Network: Wireless Public Carrier

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	93%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✗
Distribution Management System	✗

Customer Devices Installed	
In-Home Device	4,209
Direct Load Control	903
Programmable Communicating Thermostat	919
Energy Management System	367

Customers Enrolled in New Programs	
Web Portal	26,332
Time-of-Use Pricing	4,861
Critical Peak Pricing	721

AMI System and Communications: Wireless networks deployed throughout the Sacramento Municipal Utility District (SMUD) territory provide two-way communication for smart meters, customer devices, and DA equipment. Software platforms for meter data management and analysis were installed to organize, analyze, and make AMI data accessible to other enterprise systems. These systems provide SMUD with expanded capabilities to leverage interval consumption and voltage data to improve distribution system operations and overall grid reliability.

Cost Savings from Avoided Truck Rolls: SMUD reports saving more than $8.6 million in the first 13 months following AMI deployment (April 2012-June 2013) by avoiding 110,000 truck rolls (with an average cost per truck roll of about $77). SMUD's AMI system allowed it to avoid approximately $31,787,600 in meter operation costs from project initiation through March 31, 2014. The AMI system helped SMUD significantly reduce the need for manual meter operations, mainly through automated meter reading and automated service switching.

Electric Vehicle Charging Pilot with TOU Rates: SMUD conducted a residential EV program with roughly 200 vehicle participants to better understand off-peak charging potential with TOU rate options. SMUD tested two different TOU plans to determine driver satisfaction: a Whole House Time-of-Use pricing plan and a Dedicated Meter Pricing Plan that was sub-metered. The latter rate included up to 12 Conservation Days when customers were signaled to reduce load during peak hours. Both pricing plans experienced high customer satisfaction.

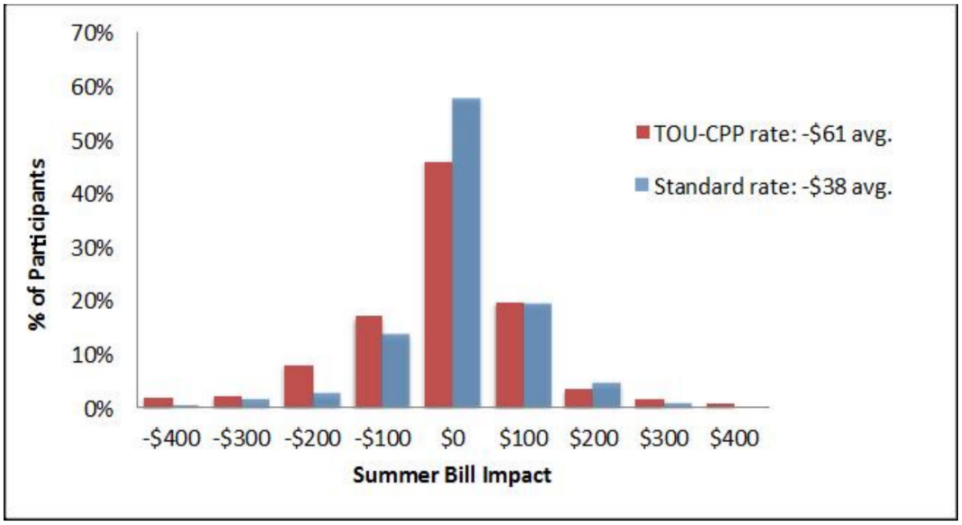
Evaluating Time-Based Rates with Customer Systems: SMUD implemented two CPP offers: one CPP-only plan and one plan that included CPP and TOU pricing. Some customers enrolled in the program were offered IHDs. The CPP rate was $0.75 per kilowatt-hour. Compared to the standard two-tiered rate, the TOU-CPP rate offered discounted off-peak pricing that accounted for 91 percent of the summer hours, higher peak pricing that accounted for 8 percent of the summer hours, and event pricing that was initiated in three-hour blocks, 12 times per summer, for a total of less than 1 percent of the summer hours. SMUD mailed IHDs to customers in the opt-in treatment group pre-commissioned, so that when they were unpacked and turned on, the devices were designed to automatically connect with the customer's meter and start displaying information.

SMUD's evaluation showed higher enrollment rates for opt-out approaches, without significant differences in drop-out rates or peak demand reductions. SMUD benefit-cost analysis showed greater net-benefits and more favorable business cases for opt-out than for opt-in, as opt-in programs typically required higher budgets for marketing and recruitment.

Customer Savings for DLC Pilots with TOU Rates: SMUD compared bill impacts for customers on TOU-CPP rates with customers on standard rates (both groups participated in a summer 2013 DLC pilot). SMUD found that TOU-CPP customers saved about 50 percent more than DLC pilot participants who chose to stay on standard rates did, as shown in Figure 15. However, the figure also shows that some customers on the TOU-CPP rate saw bill increases if they were unable to reduce or shift their electricity consumption. In 2012-2013, average summer bill savings exceeded $77 on the TOU-CPP rate for Summer Solutions participants and customers who used an IHD saw an average annual bill savings of just under $40 per year.

Based on the results of its study, SMUD is consolidating all pricing tiers to produce a single flat rate for residential customers in 2018 and may consider transitioning all residential customers to default TOU rates thereafter.

Figure 15. Summer 2013 Bill Impacts from SMUD



Testing DLC Strategies: SMUD wanted to understand how different precooling strategies, temperatures, and ceiling insulation affect demand responses. In 2012, SMUD tested three DLC strategies: business-as-usual (no pre-cooling)[18], two hours pre-cooling, and 6 hours precooling. These strategies were deployed randomly to enable more accurate evaluations. On average, no pre-cooling reduced energy use and both two and six hours increased it. Six hours of pre-cooling resulted in a reduction in overall energy use for participants with more ceiling insulation.[19]

READ MORE ABOUT SACRAMENTO MUNICIPAL UTILITY DISTRICT PROJECT ON SMARTGRID.GOV:

Sacramento Municipal Utility District Project Page

Sacramento Municipal Utility District Project Description – *November 2014*

Small Business Demand Response with Communicating Thermostats: SMUD's Summer Solutions Research Pilot – *August 2009*

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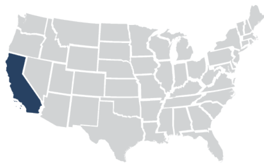
[18] Pre-cooling refers to the strategy of lowering thermostat set points before peak periods in anticipation of reductions in air conditioner operating times when under DLC.
[19] Herter Energy Research Solutions, *SMUD's 2012 Residential Precooling Study—Load Impact Evaluation*, June 11, 2013.

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

Municipal/Public Utility

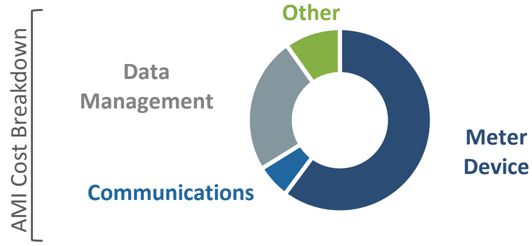


Glendale, CA

85,582 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$38,538,539**



Total Number of Meters Installed: **85,582**

Average Cost per Meter: **$450**

Communication Type: Mesh Network

Backhaul Network: Fiber

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	100%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Outage Management System	✗
Distribution Management System	✗

Customer Devices Installed		Customers Enrolled in New Programs	
In-Home Device	81	Web Portal	926

AMI System and Communications: An Ethernet/Internet protocol backhaul and a local wireless radio frequency (RF) network enable two-way communication between meters and utility data systems and allow for the monitoring and control of select distribution automation equipment. Data management systems enable GWP to develop actionable information from equipment notifications and customer electricity usage data. All capacitor banks include advanced controllers with communications devices, facilitating remote control via the supervisory control and data acquisition (SCADA) distribution management system (DMS).

Reduced Electricity Consumption from Customized Energy Reports: GWP mailed customized reports on energy consumption patterns and costs to about 46,000 households, which it says resulted in energy savings in 2011-2012 of about 5,777 megawatt-hours (4.1 percent). GWP's web portal was launched in July 2012 and resulted in a 50 percent increase in web traffic to its site, where customers can view yearly, monthly, daily, and hourly interval usage information.

Customer Systems Support Reduced Consumption: GWP offered customers in-home displays, a mobile device application, and a web portal facilitating two-way information exchange, allowing customers to view their consumption and manage their bills. GWP's customer systems programs are received favorably. For example, 83 percent of the in-home program participants are using the information provided through their in-home displays and say they have changed their energy consumption behaviors and reduced energy and water use. GWP used a digital photo frame as part of its in-home display, enabling customers to track their usage without having to go online to access the data.

Electric Vehicle and Thermal Energy Storage Pilots: GWP offered EV charging station incentives to 100 customers and plans to implement new residential time-of-use and EV charging rates for customers by June 2017. GWP also integrated AMI with thermal energy storage systems for on-peak cooling of commercial and municipal buildings using ice made during off-peak hours.

Leveraging AMI Investments for Additional Services: Outside of its SGIG project, GWP is installing a full-scale deployment of smart water meters across its entire service area, leveraging the smart grid communications network and MDMS built under SGIG.

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

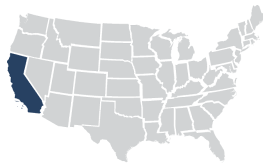
Glendale Water and Power Project Page

Glendale Water and Power Project Description – *July 2015*

Glendale Water and Power Case Study – *February 2012*

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

Municipal/Public Utility

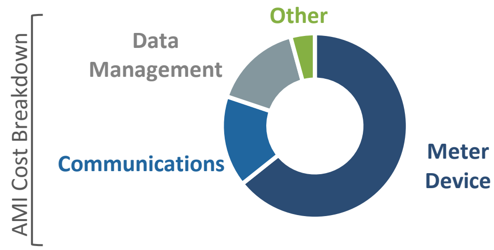


Burbank, CA

51,928 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$29,590,416**



Total Number of Meters Installed: **51,928**

Average Cost per Meter: **$570**

Communication Type: Mesh Network

Backhaul Network: Fiber

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	87%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Operations Management System	✓
Distribution Management System	✗

Customer Devices Installed	
In-Home Device	50

Customers Enrolled in New Programs	
Web Portal	2,910
Time-of-Use Pricing	200

AMI System and Communications: BWP deployed and integrated two network types: a fiber optic network and a city-wide secure Wi-Fi mesh radio frequency network. The fiber optic Ethernet network allows for monitoring and control of the electric distribution system. Radio devices in smart meters transmit data through the new Wi-Fi network. The new meter data management and outage management systems use data and notifications from smart meters and automated distribution equipment.

Reduced Field Service and Improved Customer Satisfaction: BWP used AMI to reduce field service requests by 87 percent, from about 2,500 to about 300 per month. BWP avoided a total of approximately 13,200 field trips by using the AMI systems to remotely fulfill field service requests between March 2013 and February 2014. This allowed BWP to reduce field service staff by seven positions and eliminate more than 13,200 field visits since AMI deployment. BWP can now respond to metering-related customer requests in 15 minutes or less, which is faster by hours or days than was possible before AMI. Customer satisfaction is higher as a result.

Reduced Bill Disputes and Faster Dispute Resolution: BWP's call center managers found that having timely access to detailed usage information results in greater confidence in how a bill amount was determined, thus enabling faster decision making and quicker problem resolution. This results in a higher incidence of first-call dispute resolution.

Integration with Outage Management and Distribution Automation: Last-gasp alerts are received by MDMS and relayed to OMS two minutes after receipt. This delay is inserted to allow circuit reclosers to restore power if the outage is caused by a momentary fault from surrounding vegetation. BWP's system sends power restored alerts which are processed by MDMS and OMS and used by GIS to update the company's outage map. The system also allows grid operators to test any meter to verify it has power.

BWP found it useful to dedicate resources to monitor data quality, identify anomalies, and implement corrective actions to ensure MDMS data streams were received and used properly by billing, CIS, OMS, and other systems. The utility also recommends allowing sufficient time to plan AMI deployments including logistics, asset management, records management, workforce management, and integration with communications, MDMS, OMS, and other affected systems.

Leveraging AMI Investments for Additional Services: Smart grid communications networks can be leveraged to provide additional customer services such as internet access, high-speed data access, and corporate intranets for companies with geographically dispersed facilities. Outside of its SGIG project, BWP also deployed smart water meters to all 26,000 of its water customers leveraging its smart grid communications networks.

DSM Energy Savings and Customer Bill Savings: BWP estimates lifetime DSM program energy savings at more than 8 gigawatt-hours. These savings were achieved at a cost of about $0.08 per kilowatt-hour. These savings help BWP meet state-mandated goals for energy efficiency, and keeps demand growth constant even as population and business activity increases.

In 2014, BWP estimated it saved a total of about 4.8 gigawatt hours, and reduced per-customer usage by 1-2 percent between September 2011 and 2014 as a result of customers using the BWP energy usage reports and interactive web portal. During this same period, the 25,000 participating customers in its TOU program saw more than $1 million in collective bill savings. BWP is continuing its transition to time-based rates with a new tariff for medium-sized commercial customers and implementation of an integrated automated dispatch system for demand response programs.

Thermal Energy Storage Integration: BWP integrated AMI with thermal energy storage systems for on-peak cooling of commercial and municipal buildings. These systems make ice at night during off-peak times and then provide cooling for the buildings during the day (on-peak). This shifts large fractions of electricity use for air conditioning from on-peak to off-peak periods. AMI enables integration of these ice storage systems with other types of demand response programs that reduce peak demand. BWP monitored and evaluated the ice storage units through its web portal and accounted for demand reductions using an integrated, automated dispatch system, which accessed consumption data on the units through the MDMS.

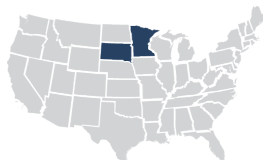
READ MORE ABOUT BURBANK WATER AND POWER PROJECT ON SMARTGRID.GOV:

Burbank Water and Power Project Page

Burbank Water and Power Project Description – *August 2014*

CASE STUDY: **SIOUX VALLEY ENERGY (SVE)**

Electric Cooperative



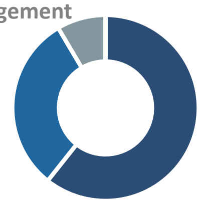
South Dakota, Minnesota

27,641 Customers

Full Scale AMI Implementation

Total Cost of AMI Implementation under SGIG: **$7,184,756**

AMI Cost Breakdown



Total Number of Meters Installed: **27,641**

Average Cost per Meter: **$260**

Communication Type: PLC

Backhaul Network: Fiber

Enabled Features on Percent of Smart Meters	
Remote Connect/Disconnect	3%
Outage Reporting	100%
Voltage Monitoring	100%
Tamper Detection	100%

AMI Integrated with:	
Billing System	✓
Customer Information System	✓
Operations Management System	✓
Distribution Management System	✗

Customer Devices Installed	
In-Home Device	84

Customers Enrolled in New Programs	
Web Portal	5,411
Net Metering	24

AMI System and Communications: Sioux Valley Energy (SVE) installed a power line carrier (PLC) network to enable two-way communications with the AMI meters and allow for monitoring and control of distribution automation equipment in both urban and rural environments. SVE monitors feeder loads, in near-real time, by aggregating smart meter data transmitted over the PLC network, improving distribution system operations and planning.

Improved Customer Service from Pre-Pay Billing Program: SVE has more than 360 customers in a voluntary pre-pay billing program. Customers can sign up for pre-paid rates with a minimum of $25.00 and allocate 50 percent of the funds to past due bills and 50 percent to future electricity use. This arrangement can be kept until the past due amount is paid off. If the customer opts-out, a deposit is required.

Sioux Valley Energy also reduced the amount charged to customers for collection trips by about 50 percent from 2007 to 2014, from about $64,000 to about $34,000.

Reduced Demand from Time-Based Rates and Testing Customer Notification: SVE's 2011 CPP pilot program involved several thousand residential and agricultural households. There were two test groups, voluntary and involuntary, and a control group for each rate class. Energy usage for the three groups of each rate class was recorded bi-hourly over the months of June, July, and August. Critical peak events charged at $0.50 per kilowatt-hour; rate during other times was discounted based on budgeted revenue from CPP rate. Table 10 shows that phone calls were the most common approach, but that text messages were preferred the most. Nearly three-fourths of the survey respondents said that they were always aware of critical peak event days after being notified by 4:00 p.m. the day before.

Table 10: SVE Notification Methods and Customer Preferences

Form of Notification	Number of Customers	Percentage Preferring the Approach
Email	93	67%
In-Home Display	55	67%
Text Messages	93	87%
Phone Call	162	68%

SVE called 24 CPP event days and found that on average volunteer participants (opt-in) reduced peak demand by about 0.79 kilowatts (residential) and 1.10 kilowatts (farm-rural), while the non-volunteer participants (opt-out) reduced demand by about 0.23 kilowatts (residential) and 1.10 kilowatts (farm-rural). SVE is developing an energy management application for smart phones to alert customers about critical peak event days.

Leveraging AMI Investments for Future Capabilities: SVE plans to design and implement end-to-end business processes to more efficiently analyze and use smart meter data, and provide automated reporting on AMI system status and billing impacts.

READ MORE ABOUT SIOUX VALLEY ENERGY PROJECT ON SMARTGRID.GOV:

Sioux Valley Energy Project Page

Sioux Valley Energy Project Description – *November 2014*

Sioux Valley Energy Case Study – *May 2012*

4 Key Lessons and Conclusions

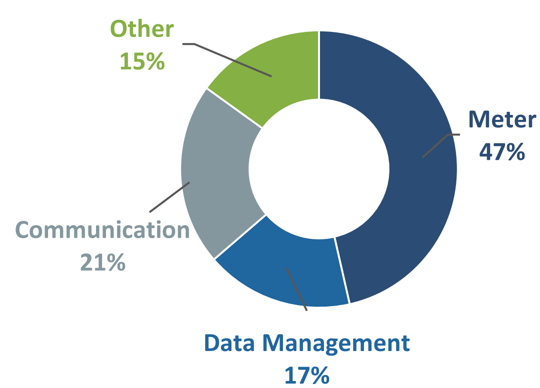
SGIG utility experiences during the AMI and customer system projects resulted in seven key conclusions and lessons learned, from technology cost and installation to systems integration and customer engagement challenges.

4.1 Multiple Factors Affect the AMI Business Case

The total cost of AMI deployment and the payback period varied greatly from utility to utility, giving insight into the myriad factors that create a utility's individual business case. Total AMI procurement and installation costs included not only the cost of the meter, but also a range of non-meter fixed costs, primarily communications equipment upgrades and data management systems. Other non-hardware costs included software and licensing fees, installation labor, information technology testing and requirements gathering, project management, software integration, and staff training.

The total AMI system deployment cost ranged from $130 to $1,895 per meter. However, only six projects reported a total installation cost above $600 per meter. Differences in how each utility defined the cost categories (meter, communications, data management, and other) partially contribute to this large variation in reported costs. However, total implementation cost—and the rate of return on investment—are determined by multiple factors:

Figure 16. Average Installation Cost per Meter Breakdown



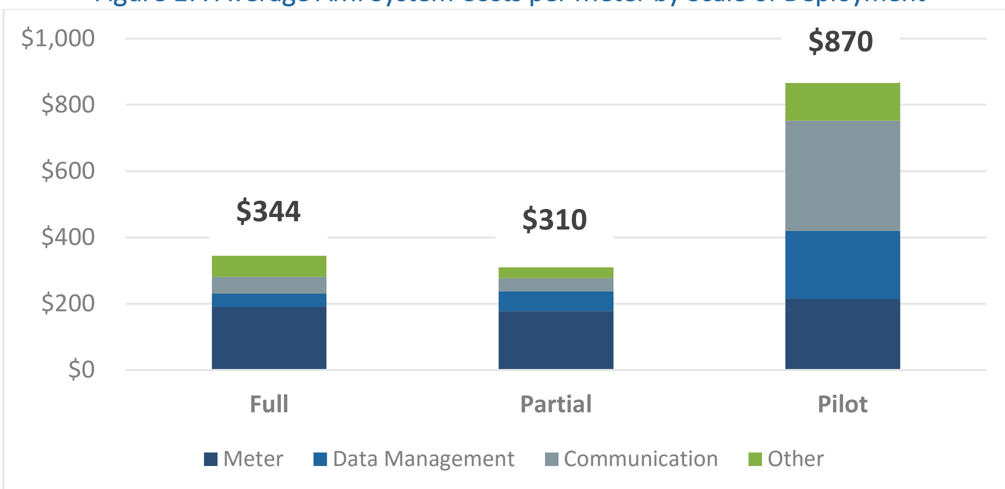
(56 AMI Projects reported this data point)

- **Full- and partial-scale implementations generally had a lower total cost per meter because AMI communications network upgrades, data management system integration, and other fixed installation costs make up more than half of the total cost per meter on average.** The meter device cost represented only about 47 percent of the total cost per meter on average (see Figure 16). The total cost per meter reported by the pilot-scale projects skews the distribution, because the integration of communications equipment and information systems is a fixed cost that is allocated across a relatively smaller numbers of meters (see Figure 17). Once the communications networks and data management systems are in place, the incremental cost per additional meter typically drops.
- **Enabling more smart meter features and integrating AMI with a larger number of utility systems can raise the total AMI implementation cost**, but also increase the value of benefits to support the business case. Additional functions enhanced revenue recovery from tamper detection, reduced outage management costs, enhanced voltage monitoring, and reduced peak demand from AMI-enabled DSM programs.
- **The utility's level of experience with AMI systems and the pre-project state of the existing communications and data management largely contributed to overall cost.** Some utilities used

their SGIG projects to upgrade large portions of their communication systems to support multiple smart grid technologies beyond AMI. Software testing and systems integration proved challenging for some projects, raising the total cost.

- **Customer outreach and education contributed to overall cost, and varied by project.** Some utilities experienced push-back from customers that were concerned about the perceived risks of smart meter health effects and data privacy intrusions. Smart meter opt-out provisions mostly addressed these concerns, and in all cases, opt-out rates were low and did not raise deployment costs significantly.

Figure 17. Average AMI System Costs per Meter by Scale of Deployment



(56 AMI Projects reported this data point)

Note: While a larger number of meters installed typically resulted in a lower total cost per meter, one full-scale project with particularly high costs can skew the average—resulting in a higher full-scale cost per meter. The data is based on a small number of utilities with a wide range of starting points and project activities.

4.2 Communications Systems that Serve Smart Grid Functions Beyond AMI Deliver More Value

Utilities accrue additional advantages when they design communications networks that have the bandwidth, latency, and capacity to serve other needs, such as DA and DSM, in addition to metering and billing. Many utilities leveraged high-capacity communications networks to serve a variety of needs, including gas and water metering and to offer internet and file transfer services to customers.

Communications networks are the backbone of all smart grid deployments, including AMI and customer systems. Utilities leverage a variety of wired and wireless communications technologies to support their smart grid applications and functionalities. As with any other component of their smart grid deployment, utilities must consider how a given technology fits with their operational goals, service area characteristics, and business process constraints.

Investment options include wireless mesh, fiber optics, and power line carrier. For backhaul networks, some utilities chose to contract third-party telecommunication vendors for access to high-speed cellular networks.

Wireless mesh networks can offer advantages over other wireless network topologies in terms of reliability, adaptability, and installation and maintenance costs. Mesh communications depend on peer-to-peer communications and are generally better suited to densely populated areas. Fiber optic cables offer high bandwidth, low latency, and high reliability, but have relatively higher costs and may be better suited to urban deployments that build on legacy fiber networks already in place. These systems may not be as compatible with utilities that have hilly terrains or that span large geographic areas because of added costs for ensuring adequate radio coverage.

4.3 Systems Integration is a Critical Linchpin for AMI Impacts and Benefits

Deploying AMI technologies and systems is a complex undertaking for utilities. Implementing these new capabilities requires utilities to rethink many business processes and procedures and address many new technical challenges involving information management and data communications. For large-scale deployments, implementation typically involves multiple utility business units, vendors and contract installers, regulators, customers, and local government agencies. Deployment challenges included designing communications networks that meet overall system design requirements and enable planned deployments, addressing systems integration issues, educating customers about smart meter benefits and installation requirements, and addressing customer concerns about the health and data privacy issues associated with smart meters. Integrating meter data with other systems and functions often 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.

For many of the 62 demand-side projects, managing the large quantities of information about customer electricity consumption has proven to be a significant challenge. Utilities have encountered issues in data transmission, data processing, error checking, and integration with legacy systems.

Effective AMI, MDMS, CIS, and Billing Integration Greatly Enhance Billing and Metering

Billing and metering services are enhanced when AMI, MDMS, CIS, and billing are integrated and operating properly. Service is more accurate with fewer customer queries and complaints, customer satisfaction levels are higher, and utility operating expenses are lower. To realize these favorable impacts, thousands of access points, communications devices, and meters need to work together to form new networks with seamless collections of meter readings and enhanced data processing for more accurate bills and data presentments through web portals.

Successful integration often involves development of new data analytics and algorithms for identifying thefts from tamper detection alerts and unusual consumption patterns. Many utilities maintain extensive estimated billing processes and procedures that are often no longer needed with successful integration of AMI and billing systems.

Effective MDMS is paramount for ensuring meter data accuracy, successful integration with other utility systems, and for serving a variety of smart grid purposes. After communications networks deliver interval data from smart meters to head-end systems at utility headquarters, the next step involves processing by MDMS for error checking and formatting for CIS, billing, and other system needs.

For many utilities, MDMS serves as the single repository for all interval usage, register reads, and event meter data. MDMS captures and validates all meter readings (legacy meters and smart meters) and calculates bill determinants when requested by the billing or customer service departments. In this way, MDMS is integral to the AMI billing and metering services function. MDMS can be programmed to handle complicated rate structures of all types including time-based rates, incentive programs, and pre-pay billing plans.

Participating SGIG projects experienced MDMS integration challenges and lessons learned:

- Baltimore Gas and Electric (BGE) found the integration software it used did not at first export meter reads in the format that its MDMS could process. BGE developed "converter" software to translate AMI format to MDMS format, which added complexity to the data flow between the two applications, but was necessary for the system to operate properly.
- Burbank Water and Power (BWP) found it useful to dedicate resources to monitor data quality, identify anomalies, and implement corrective actions to ensure MDMS data streams were received and used properly by billing, CIS, OMS, and other systems.
- PECO took steps to ensure that all interval data processed and sent from meters through MDMS to other systems and external parties remained properly time-stamped and synchronized. This involved development of audit mechanisms for data validation.
- Lakeland Electric initially attempted to install a revision of its legacy MDMS, which was originally used for processing monthly reads to process hourly reads from smart meters. However, Lakeland found this revision to be ineffective as a data extraction and validation tool.

Accurate and timely billing is an essential function for utilities, so successful integration of AMI and MDMS with billing systems is a top priority. CIS integration is also important for tasks such as equipping customer service representatives with billing data to resolve customer queries and for providing consumption and cost data for customized customer web portals.

The most common interoperability issues occurred when utilities procured AMI, billing, and CIS from different vendors and these systems involved different data inputs, outputs, and formats. Such differences in data handling and processing frequently meant that utilities needed to develop specialized software and data formatting tools to ensure error-free data transfers. These integration issues increased costs and had an adverse impact on the project schedule. Other interoperability issues arose for utilities when upgrading legacy billing systems to support new AMI functions, rather than investing in new ones.

OMS and DMS Integration Increases the Value of Smart Meters

Successful integration of AMI with OMS and DMS can boost electricity reliability and customer satisfaction from fewer and shorter outages. Meter pinging practices are an essential component to realizing these benefits. Integration of OMS and AMI allows the OMS to receive last-gasp and power-on notifications from smart meters, and thus display meter outage status to the control room personnel. With these capabilities, repair crews can quickly determine the location of outages and nested outages, improve outage restoration times, reduce truck rolls, and determine the best course of action to restore service to customers.

Utilities typically customize their outage monitoring and meter pinging protocols to increase efficiency and effectiveness and to manage costs. Some utilities use AMI for pinging all meters to make initial assessments when widespread outage events are underway, and subsequently use GIS tools to create outage maps for monitoring progress as restoration activities begin.

Many utilities then implement automated neighborhood- or feeder-specific meter pinging focused on troubled areas and likely locations for nested outages, which normally take longer to detect and resolve. These practices save time following an outage so that control room operators do not have to undertake manual pings. Other utilities sometimes turn off the automated last-gasp notifications in the initial phase of outage restoration, when the emphasis can be on resolving issues at affected substations and transformers and barrages of meter alarms overwhelm OMS screens. Last-gasp notifications are then typically reactivated later when major outages have been located and the number of meter notifications is manageable.

AMI-OMS integration typically involves one or more of the following AMI-related functions:

→ **Outage notification**, where last-gasp or power-off smart meter alarms are recorded and assessed for automatically initiating outage events in the OMS. The power-off notifications are typically sent to the OMS and for use with customer calls that have been received to identify outage locations.

→ **Restoration verification**, where automatic power-on notifications are used to verify service and document restoration times in the OMS.

→ **Nested outage identification**, where small pockets of customers are displayed that may still be without power due to a local equipment issues that may not have been repaired when the larger outage was restored.

→ **Restoration time and field dispatch efficiency**, where field crews are equipped with smart meter and OMS data and displays to accelerate repair activities and better manage labor resources and truck roll for restoration activities.

Customer Systems Integration Involves Interoperability Challenges

Integration of AMI and CIS with web portals, time-based rates, incentive programs, and customer devices such as PCTs, IHDs, HANs, and energy management systems is a new area involving rapidly evolving technologies and needs for upgraded standards and data transfer protocols. The process is complicated because communications and data transfer straddle the utility and customer sides of the meter.

Most utilities aimed to invest in devices and systems that were interoperable with ZigBee-compatible components. Several of the utilities deploying PCTs and IHDs set out to accomplish systems integration and data transfer between smart meters and these devices using HANs. In many cases, IHDs were set up to communicate with smart meters to display usage information, time-based rates, and critical peak event alerts. Other utilities aimed to use HANs to control other customer devices like water heaters and swimming pool pumps.

Participating SGIG projects experienced a variety of scenarios while integrating customer systems:

- Florida Power and Light (FPL) used near-real-time energy information from the smart meter's HAN radio in its time-based rate pilot program. FPL found that the HAN technologies, standards, and data transfer protocols were still in their developmental stage. The HAN communication protocol that was available for pilot use, Smart Energy Protocol 1.0 (SEP 1.0), is non-specific, making interoperability or "plug and play" between smart meters and HAN products not possible to achieve. FPL was one of many utilities that ran into this issue.

AMI and DA Integration Boosts the Value of Individual Technologies

DA assets, technologies, and systems also play key roles in supporting or enabling these new functions and capabilities.[20] **Integrating AMI and DA is thus a top priority and major technical challenge for many utilities seeking to modernize grid operations and boost reliability, resilience, and voltage optimization.**

Due to fundamental changes in business process and practices from deployment of automated systems, staff development and training is a key implementation step. Meters and sensors produce large volumes of data to process, store, analyze, and turn into actionable information for grid operators and repair crews. Many utilities are implementing more decentralized approaches by equipping repair crews with information management systems supported by meter and sensor data to improve work management, optimize labor resources and costs, and accelerate service restoration and maintenance and repair activities. Utilities are also addressing new needs for cybersecurity protections and interoperability needs.

4.4 Workforce Management and Training are Critical to AMI and DSM Success

Integrating AMI deployment with internal project implementation processes and workforce management systems (WMS) is challenging because AMI deployments are complex and involve multiple business units. This manifests in the need for sufficient up-front planning, accurate GIS record-keeping of meter locations, management of AMI vendors and installation contractors, processes for interim billing during meter switch-outs, management of software version upgrades, and transition from implementation to operations. Integration activities and lessons learned include:

- BWP recommends allowing sufficient time to plan AMI deployments including logistics, asset management, records management, workforce management, and integration with communications, MDMS, OMS, and other affected systems.
- CMP formed a user group with other utilities to share information about problems and solutions and provide guidance for specifications to vendors. CMP found it helpful to share project goals with vendors because it helped keep implementation tasks and milestones in alignment with the project's overall aims.

[20] U.S. Department of Energy, *Distribution Automation: Results from the Smart Grid Investment Grant Program*, 2016.

- Pepco experienced problems changing-out meters located in basements or residential garages. In some cases, room surveys were required to determine the best change-out approach and most effective means for reliable telecommunications of meter data. The communication network vendor surveyed hard-to-access meters and Pepco recommends that such surveys be done prior to meter installation.
- Central Lincoln Peoples Utility District recommends developing a meter numbering system that includes establishing GPS locations for all meter locations. This step helps meter deployments but also makes integrations with OMS and GIS easier to accomplish.

Integration examples from the SGIG projects involving project communications and workforce management include:

- Workforce training (including installation contractors) was effective for several SGIG projects. Pepco implemented a successful training program for meter switch-out contractors to repair damaged meter sockets. Central Lincoln assigned company staff to support and train contract meter installers. PNGC recommends requiring proper training, orientation, and live support from AMI vendors, particularly when interactions with customers are required.
- Lakeland Electric and other utilities found that in many cases vendor software did not always meet specifications and required version changes, which led to certain features not being implemented on time, or in some cases, not at all. CMP found that the need for frequent upgrades presented challenges for minimizing disruptions to customers, which meant that more rigorous meter testing was required than anticipated. CMP developed a testing protocol involving more than 50 meters located in the field.
- PECO developed internal and external communications to manage its smart meter deployment. Internally it held regular meetings, developed standard messaging, and implemented a dedicated intranet page to help with workforce management and training. Externally, PECO developed standard messages, talking points, print materials, web pages, and community event presentations for communications with the public and local media.
- After researching the experiences of other utilities, CMP performed a bottom-up assessment of the tasks and skillsets required to support AMI deployments and operations. This effort assisted workforce management and helped guide the transition of the metering department to the new AMI system.
- Duke Energy also focused on transition planning from old to new ways of doing business under AMI. Duke's "turnover to operations" plans were a key part of its project management process. Turnover plans require that operation of a specific smart grid capability is not turned over from the project implementation team to routine operating departments until new business processes have been developed and tested and formal change management procedures have been implemented, including sign-offs from appropriate business units.

Time-based rate and incentive program implementation often requires utilities to develop new capabilities and skill sets in areas such as:

- Market research to assess customer needs and wants
- Marketing and advertising campaigns to recruit customers to enroll in programs
- Customers services and call centers to respond to customer queries about new rate and program offerings

- Database management for information on customers and participation and integration with CIS, billing, and other systems
- Data analysis for evaluating customer acceptance, retention, and responses
- Regulatory support for gaining approvals for program designs and implementation activities

4.5 Cybersecurity and Interoperability Are Integral to Smart Grid

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

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

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

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

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

Interoperability is also critical in a modern grid because it enables two or more networks, systems, devices, applications, or components to share and readily use information securely and efficiently with little or no inconvenience to the user.[21] Since 2009, the industry has made substantial progress in tackling key interoperability issues, and the SGIG projects were important for evaluating deployments, assessing needs, and accomplishing key activities in accelerating interoperability development.

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

SGIG utilities shared valuable lessons learned from implementing their CSPs and shared them with peers during the 2012 Cybersecurity Information Exchange. [22] Insights from the SGIG utilities include:

- **Early cybersecurity planning with product vendors is key**. Develop cybersecurity specific procurement contract language and consider early engagement of 3rd-party software suppliers when planning smart grid investments. Demand that products meet cybersecurity standards and define those standards early. Provide strong contractual language in proposal requests. Request that vendors take responsibility for security and vulnerability mitigation over the full product lifecycle.
- **Ensure interoperability through robust testing with manufacturers and industry partners**. Collaborate with manufacturers to develop robust test environments that are fully representative of all factors in the field. Become active in national partnerships and support emerging smart grid cybersecurity standards. Create interoperability with legacy systems through gateway proxies and service buses.
- **Obtain strong cybersecurity support from executives and managers**. A CSP should behave like a business plan that includes a budget, defined risk, metrics and evidence, and is written so that senior management can understand it. Obtain upfront management support and resources, tie security needs to the business strategy, and communicate the business implications of cybersecurity investments. Keep executives informed throughout a project.
- **Eliminate company silos and define clear cybersecurity roles and responsibilities**. Undefined personnel roles and responsibilities are major obstacles and must be established at the beginning of any cybersecurity program. Company "silos" must be crossed so that the cybersecurity program is well understood by multiple stakeholders. Employees must work to narrow the gulf between operations and IT staff to fully address cybersecurity.
- **Conduct workforce training to build cybersecurity expertise and literacy**. There is often a lack of common vocabulary on cybersecurity issues and enterprise-wide cultural change is often needed. Utilities should conduct training to build deep cyber expertise for key staff, but also support cybersecurity training for all technical staff to promote awareness and familiarity across the organization.

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

4.6 Designing and Promoting Effective Web Portals Involved Several Challenges

Many utilities that deployed smart meters with web portals experienced difficulties attracting customers to access and use their web portals. Many customers were either unaware of the existence of the web portals or did not bother to enroll and use it. Several SGIG utilities implemented education and outreach activities to boost web portal usage with favorable results.

Simplified interfaces are best; participants found that customers want rapid and often self-guided access to the information they need. Examples of SGIG web portal and electronic communications experiences include:

- Central Lincoln Peoples Utility District's customers can monitor and manage their energy usage through the web portal, which was accessible via home computer or mobile devices. Energy usage is presented by year, month, week, day, and 15-minute intervals and overlaid with daily temperature. Customers can compare their energy usage to others with similar home characteristics, challenge themselves to save energy, and receive alerts when they are using more electricity than usual.
- Jacksonville Electric Authority's web portal includes a web-based tool that provides energy and water consumption information and contains utility management tools, billing and payment information, and energy conservation tips.
- Baltimore Gas and Electric's web portal enables customers to view bill estimates, receive unusual usage alerts, compare their usage to "like" customers, receive personalized usage and savings tips, and receive printed and electronic home energy reports.
- Entergy New Orleans' SmartView pilot used web portals to inform participants about how they can reduce electricity consumption during critical peak events. In this application, 82 percent of customers said they were "very" or "somewhat" satisfied with the web portal's usefulness as a decision-making tool, compared to 94 percent for IHDs and 90 percent for PCTs.

4.7 Customer Education Improves Demand Response Programs

Overall, utilities found that they needed to plan customer system deployments carefully and include resources for customer engagement and outreach activities. They found that effort was needed to ensure that supporting systems are appropriately selected, configured, integrated, and maintained, and that targeting and recruitment efforts are properly resourced. Getting customer communications "right" is essential for success. Utilities must be prepared to dedicate sufficient resources to the trial-and-error of the education process.

For example, Entergy New Orleans provided three types of training to participating customers: face-to-face training involved 32 training sessions throughout the city, involving more than 500 customers; over-the-phone training involved ten conference-call training sessions for about 170 customers; and mail instructions to about 2,000 customers, which invited the customer to call the customer support center or visit the utility. Initially, Entergy mailed preconfigured HAN devices, but customer calls and home visits by customer service agents were sometimes required when participants experienced meter synchronization issues.

5 Future Directions and Next Steps

The SGIG AMI and customer systems projects invested more than $5 billion in new technologies, tools, and techniques for grid modernization. While substantial, this investment represents a relatively small portion of the total level of investment that the electric power industry is expected to make in grid modernization over the next several decades. The SGIG projects were specifically designed as learning opportunities, providing the electricity industry with additional data on smart grid performance and lessons learned that can catalyze continued investment in smart grid technologies and systems in the coming years.

The majority of SGIG recipients are building upon initial project results by expanding technology deployments, offering successful pilot programs to more customers, or improving the integration of AMI with other data and information management systems to extract additional value from deployed technologies or activate new smart meter capabilities.

5.1 SGIG Utilities Largely Plan to Expand AMI and Customer System Investments

In general, SGIG utilities that deployed smart meters system-wide are now planning to develop and deploy technologies, tools, and techniques that further enhance customer services. The most common planned applications include AMI-enabled pre-pay programs, time-based rates, voltage monitoring, and DER and EV integration. Together, these solutions will give customers more options to manage their electricity bills, reduce peak demand, optimize voltages, and facilitate customer adoption of DER and EVs:

- **Expanding Pre-Pay Programs**: Several public power and electric cooperatives are moving ahead with plans to implement pre-pay programs for residential customers. One of the IOUs, NV Energy in Nevada, is also planning to implement pilot-scale, flexible payment programs to assess customer acceptance.
- **Offering New Time-Based Rate and DSM Programs:** Several of the utilities are planning to implement new TOU rates to encourage customers to shift consumption to off-peak periods. Others are developing new applications to support better customer engagement in DSM programs. For example:
    - Oklahoma Gas and Electric filed a request, which was approved by the Oklahoma Corporation Commission, to roll out its VPP rate offering with free PCTs under an opt-in recruitment approach with the goal of enrolling 120,000 (approximately 20 percent) of its residential and small commercial customers across its service territory within 3 years.
    - SMUD is consolidating all pricing tiers to produce a single flat rate for residential customers in 2018 and may consider transitioning all residential customers to default TOU rates thereafter.
    - Burbank Water and Power in California is continuing its transition to time-based rates with a new tariff for medium-sized commercial customers and implementation of an integrated automated dispatch system for demand response programs.

- Tri-State Electric Membership Corporation and Cleco Power in Louisiana plan to offer new TOU rates to their customers to manage peak demand. Both plan to offer the new rates in conjunction with displaying usage data on their web portals.
    - Sioux Valley Energy is developing an energy management application for smart phones to alert customers about critical peak event days.
    - Baltimore Gas and Electric in Maryland plans to evaluate deployments of Wi-Fi thermostats and test whether they are interoperable with the AMI network and result in greater peak demand reductions and customer satisfaction.
    - South Kentucky Rural Electric Cooperative Corporation (SKRECC) plans to introduce AMI-enabled time-based rate programs to its members (pending Kentucky Public Service Commission approval). SKRECC also plans to expand DLC programs to include commercial and industrial customers once the technology options have been fully evaluated.
    - Demand response service provider EnerNOC (formerly M2M Communications) plans to expand its irrigation pump DLC program developed under SGIG in California to other states. The irrigation load-management program can be customized and employed wherever utilities with significant summer irrigation loads desire to reduce peak demand.

- **Expanding Use of AMI for Voltage Optimization and CVR**: Several of the utilities plan to expand use of AMI-enabled voltage monitoring capabilities for automated volt/VAR controls, including CVR:

    - Central Lincoln Peoples Utility District plans to implement its CVR program system-wide after the pilot resulted in 2 percent energy savings for all customers.
    - The City of Fulton in Missouri plans to leverage the AMI system's voltage monitoring capabilities to improve voltage quality across the system.
    - The City of Naperville in Illinois is working on the deployment of a CVR program for energy efficiency and peak demand reduction.
    - Cobb Electric Membership Corporation is experimenting with the use of remote disconnect meters as controls for capacitor banks within its distribution system.
- **Continued Support for DER and EV Charging**: Several utilities plan to leverage AMI systems to facilitate customer adoption of DER and EVs.

    - For example, Glendale and BWP plan to implement new EV charging rates based on pilots.
    - FirstEnergy plans to leverage data from smart meters and distribution line sensors to develop feeder models to support the designing, upgrading, and operating of distribution systems with high penetrations of rooftop photovoltaics and energy storage systems.

Many of the utilities are exploring ways to make better use of AMI deployments through improved integration with other corporate functions and information and management systems. For example, some of the utility AMI business cases did not anticipate the full extent of benefits of using AMI data for outage management and power restoration efforts. These utilities now plan to upgrade OMS to fully integrate AMI systems and smart meter data.

Almost half of the projects implemented AMI in small-scale (<20 percent of customers; 11 projects) or partial-scale (20-90 percent of customers; 20 projects) deployments. Many of these utilities now plan to expand smart meter deployments to more customers and services. For example, PECO, a large IOU in Pennsylvania, used DOE funds to deploy smart meters to about half of its customers, and plans to deploy smart meters system-wide. Similarly, Westar Energy in Kansas currently plans to deploy an additional 200,000 smart meters over the next five years, building on the initial deployment under SGIG of almost 50,000 smart meters.

Advanced communications networks deployed under SGIG constitute the backbone of not only a smart grid, but also future smart cities. Three municipal utilities—which each offer both electricity and water services—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 other city services in addition to electricity. Smart grid communications networks can be leveraged to provide additional customer services such as internet access, high-speed data access, and corporate intranets for companies with geographically dispersed facilities.

Several municipal utilities provide gas and water services in addition to electricity, and plan to expand AMI to cover these other services while leveraging the communications network and MDMS built under SGIG. For example, GWP and BWP deployed smart water meters (outside the SGIG project) leveraging the AMI communications network.

5.2 AMI and Customer System Projects Highlighted Continuing R&D Challenges

Advances in data analytics could help utilities extract additional benefits from the large volume of interval load data produced by AMI. Utilities require better data processing and management solutions, advanced software platforms, and improved models for assessing system conditions and predicting demand impacts and energy savings levels.

Consistent data formats and more comprehensive interoperability standards are needed to achieve optimal levels of interoperability for smart meters, customer devices, and communications and information systems. Several utilities indicated a desire to see these issues resolved and observe sustained system performance at desired levels before considering further investments in AMI and customer systems. DOE supports continuing efforts in these areas, including the Green Button Initiative, which provides a standard format for energy usage data now used by utilities and vendors serving more than 60 million businesses and households. The Smart Grid Interoperability Panel, along with other efforts, has also had success in developing tools and techniques for customer data and interoperability.

AMI deployments raise new questions about the security of customer data, the types of entities that can access it, and how the data will be protected from cybersecurity breaches and other data privacy intrusions. DOE supports implementation of appropriate data privacy protections and participated in a collaborative process through the Voluntary Code of Conduct, which developed general principles for ensuring customer energy usage data privacy for utilities and third parties. Cybersecurity and interoperability remain important technical challenges for modernizing electric distribution systems. Standards, protocols, tools, and techniques are needed for ensuring secure and interoperable technologies and systems. Success in these areas involves ongoing activities for government and industry, including changes in regulations, business practices, and consumer data privacy protections.

There are many opportunities to make smart appliances and building energy management equipment on the customer's side of the meter more "grid-friendly." Proper characterization, improved interoperability, and new controls are required to enable the optimal coordination of electrical resources housed within buildings and industrial plants. Residential and commercial buildings, and industrial facilities, consist of many physical assets that can be regarded as an energy ecosystem. From power sources (DER), to loads (appliances and machines), to storage (batteries and thermal energy) and controls (building energy management systems), buildings and industrial plants can have all the components that form an integrated electric power system.

However, communication and control capabilities are limited among these various assets, and interoperability standards are yet to be developed. This results in numerous proprietary control and communication standards developed by independent manufacturers. Automated and grid-responsive equipment can be designed to detect voltage and frequency fluctuations or respond to signals from control systems. However, challenges remain with ensuring that these devices will be capable of providing grid services without jeopardizing the quality and reliability of their primary functions of serving building and occupant needs.

Continued innovations in applications and tools that operate on mobile devices (e.g., mobile phones, tablets, and laptop computers) can help customers by putting data on consumption and costs into their hands when they need it and in forms they can readily use. DOE is supporting innovations in devices and software for enhancing consumer engagement in DSM programs. Industry research by the Smart Grid Consumer Collaborative and other organizations find that the average consumer knows little about how electricity is generated, distributed, and consumed, the impact of using it, or how to maximize efficiency and cost savings. DOE participates in Power over Energy, which helps industry participants to engage and encourage consumers to become more active and informed participants in energy technologies, markets, and discussions about regulatory policies.

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

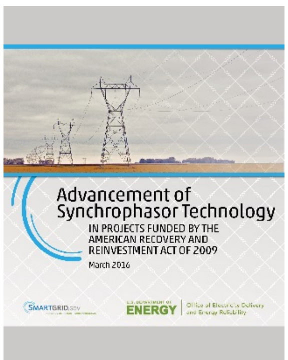
While the SGIG program is now complete, grid modernization remains an important national priority. DOE through the Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid and how DOE will help achieve this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will assist DOE in developing and implementing the activities in the MYPP. [23]

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

APPENDIX A.
Where to Find Additional Information

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

A.1. Final SGIG Analysis Reports



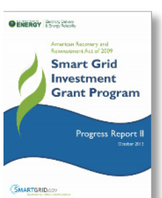
Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009

2016

Distribution Automation: Results from the Smart Grid Investment Grant Program

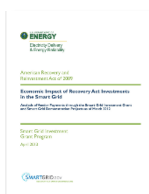
2016

A.2. SGIG Program Interim Progress Reports



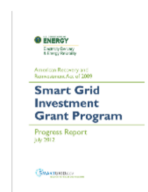
Smart Grid Investment Grant Progress Report 2013

September 2013



Economic Impact of Recovery Act Investments in Smart Grid

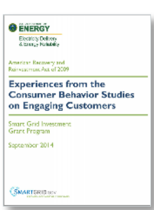
March 2013



Smart Grid Investment Grant Progress Report 2012

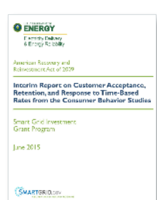
July 2012

A.3. Consumer Behavior Studies Reports



Experiences from the Consumer Behavior Studies on Engaging Customers

September 2014



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

June 2015

See more Consumer Behavior Study program reports and individual utility studies on the Consumer Behavior Studies page.

A.4. Key Interim SGIG Analysis Reports

	Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems - Initial Results	Dec 2012
	Operations and Maintenance Savings from Advanced Metering Infrastructure - Initial Results	Dec 2012
	Reliability Improvements from the Application of Distribution Automation Technologies - Initial Results	Dec 2012
	Application of Automated Controls for Voltage and Reactive Power Management - Initial Results	Dec 2012
	Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs	Aug 2013
	Customer Participation in the Smart Grid – Lessons Learned	Sep 2014
	Municipal Utilities' Investment In Smart Grid Technologies Improves Services and Lowers Costs	Oct 2014
	Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response	Nov 2014
	Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors - Experiences from Six Smart Grid Investment Grant Projects	Dec 2014
	Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration	Dec 2014

A.5. AMI and Customer System Case Studies

	Reducing Peak Demand to Defer Power Plant Construction in Oklahoma	OG&E	May-11
	Smart Meter Investments Support Rural Economy in Arkansas	Woodruff	Jul-11
	Smarter Meters Help Customers Budget Electric Service Costs	Tri-State	Sep-11
	At the Forefront of the Smart Grid: Empowering Consumers in Naperville, Illinois	City of Naperville	Sep-11
	Agricultural Demand Response Program in California Helps Farmers Reduce Peak Electricity Usage, Operate More Efficiently Year-Round	M2M Communications	Nov-11

	Vermont Pursues a Statewide Smart Grid Strategy	eEnergy Vermont	Nov-11
	Glendale, California Municipal Invests in Smart Grid to Enhance Customer Services and Improve Operational Efficiencies	GWP	Feb-12
	CenterPoint Energy's Smart Grid Solutions Improve Operating Efficiency and Customer Participation	CenterPoint	Feb-12
	Transforming Electricity Delivery in Florida	TEC	Mar-12
	Critical Peak Pricing Lowers Peak Demands and Electric Bills in South Dakota and Minnesota	SVE	May-12
	Smart Grid Solutions Strengthen Electric Reliability and Customer Services in Florida	FPL	Jun-12
	Demand Response Defers Investment in New Power Plants in Oklahoma	OG&E	Mar-13
	Smart Meter Investments Yield Positive Results in Maine	CMP	Jan-14
	Smart Meter Investments Benefit Rural Customers in Three Southern States	Tri-State	Feb-14
	Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas	Duke Energy	Aug-14
	Automated Demand Response Benefits California Utilities and Commercial/Industrial Customers	Honeywell	Aug-14
	Smart Grid Technologies Cut Emissions and Costs in Ohio	AEP Ohio	Oct-15
	Demonstrating Coordinated Resources in the Pacific Northwest	Battelle	Oct-15
	Making Electricity a Value Proposition for the Consumer	Pecan St.	Oct-15
	Power to the People: Advanced Meter Reading Supports Consumer Programs	NSTAR 292	Oct-15
	Improving Security in the Growing Smart Energy Corridor	LIPA	Oct-15
	Renovating the Grid and Revitalizing a Neighborhood	KCP&L	Oct-15

See more project Case Studies on SmartGrid.gov.

APPENDIX B.
Approach to Analysis and Data Collection

The 70 Smart Grid Investment Grant (SGIG) advanced metering infrastructure (AMI) and customer system projects collected and analyzed data about the deployed technologies and systems, grid impacts, benefits, and lessons learned.

The U.S. Department of Energy (DOE) compiled this information for analysis of AMI and customer system operations, and for sharing with the electric power industry through DOE's **Smart Grid Investment Grant (SGIG) website**.

The primary purpose of SGIG's data collection and analysis activities is to provide electric power industry decision makers, public and private, with information to help assess the cost-effectiveness of investments in AMI and customer systems. The goal is to help accelerate modernization of the nation's electric distribution systems.

B.1. Analysis Approach

Figure B-1 shows the overall DOE approach for analysis of SGIG AMI and customer system projects.[24] The analysis begins with assessments of the deployed ***smart grid assets***. These assessments include the technologies and systems, such as smart meters and in-home displays, and how they can be installed and operated by the SGIG utilities, vendors, services providers, and participating customers. The next step involves assessments of the new ***smart grid functions*** that the new assets enable. This includes assessments of the new functions and capabilities, such as remote connections/disconnections and demand management, and how to make them operational to achieve certain grid, customer, and societal impacts and benefits.

Figure B-1. SGIG Analysis Approach

The third step involves assessments of the ***smart grid impacts***, which generally includes analysis of specific physical metrics that measure changes resulting from deployment of assets and implementation of functions to achieve improvements in operational efficiencies or reductions in peak demands. The last step involves the determination of ***smart grid benefits***, which generally includes monetization of the impacts for use in business case analysis, such as cost savings or deferral of capital investments.

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

Benefits analysis can include utility, customer, and societal perspectives and covers two general types of benefits: those that can be monetized, such as cost savings, and those that are difficult to monetize, such as reductions in environmental emissions or increases in customer choices, services, and satisfaction.

B.2. Data Collection Approach

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

The plans were developed through a series of meetings between DOE and the project teams and outlined the specific data to be collected and when and how it would be reported to DOE. Each plan discussed two separate sets of data collection efforts: Build Metrics and Impact Metrics.[25]

- **Build Metrics** comprise the set of devices and systems that the projects purchased and installed; for the duration of the program, this information was posted and updated on the SGIG website every six months to inform stakeholders of SGIG projects' progress. AMI and customer systems build metric data includes information on the numbers and costs of installed devices and systems.
- **Impact Metrics** comprise the set of information developed by the SGIG projects to assess the effects of the new technologies and systems on grid and customer operations and business practices. Impact Metrics submissions to DOE occurred twice a year and required the projects to collect and analyze information to show how the installed technologies and systems operated to achieve grid modernization objectives in several key areas: billing and metering services, demand management, revenue collections, voltage controls, and outage management.

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

B.3. Scope of Data Collection

Table B-1 lists the build metrics that were collected for the SGIG AMI and customer system projects. Because each of the projects had its own unique scope and objectives, not all of the SGIG AMI and customer system projects provided information on all of the build metrics in Table B-1.

[25] DOE's SGIG website contains addition information on the approach to build and impact metrics.

Table B-1. List of Key AMI and Customer System Build Metrics for SGIG Projects

Key AMI and Customer System Build Metrics
• Smart meters • AMI and backhaul communications systems • Meter data management systems (MDMS) • Customer information/billings systems • Load control switches • In-home displays (IHD) • Programmable communicating thermostats (PCT) • Smart appliances • Home area networks (HAN) • Web portals

Table B-2 lists the impact metrics that were provided by the SGIG AMI and customer system projects. Because each of the projects had its own unique scope and objectives, not all of the projects provided information on all of the impact metrics in Table B-2. In addition, the methods used by the projects to estimate impact metrics varied so it was necessary for DOE to categorize and analyze the data for presenting appropriate comparisons and information summaries.

Table B-2. List of AMI and Customer System Impact Metrics for SGIG Projects

Impact Areas	Impact Metrics
Billing and metering services	• Reduced labor hours for metering, billing, and customer services • Reduced truck rolls and vehicle miles • Reduced variances and bill discrepancies • Reduced non-paying accounts • Faster service order fulfillment • Reduced electricity consumption • Reduced levels of peak demand • Reduced barriers to adoption of DER
Demand-side management (DSM)	• Reduced electricity consumption • Reduced levels of peak demand • Enhanced customer capabilities to manage consumption and costs • Reduced customer service labor hours
Revenue collections	• Reduced non-paying accounts
Outage management and voltage monitoring	• Faster service restorations • Reduced labor hours and truck rolls for service restorations • Reduced electricity consumption • Reduced levels of peak demand

B.4. Challenges and Limitations

DOE's data collection and analysis activities have produced a variety of reports and case studies on results and lessons learned from the SGIG AMI and customer systems projects.[26] The extent of the analysis is limited in various ways due to challenges that the SGIG AMI and customer systems projects faced during the data collection and analysis process.

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

For example, some projects used control groups to assess before-and-after impacts from time-based rate and other demand response programs. This technique was complicated in many cases by the need to make randomized assignments of participating customers to treatment and control groups so that the causes of impacts on key metrics such as demand reductions could be determined to be the result of project activities versus other, potentially confounding factors such as differences in customer demographics. Some projects were successful in accomplishing randomized assignments for treatment and control groups and DOE's analysis focused on the experiences and reported results from these.[27]

Another challenge with AMI and customer system data collection and analysis concerned the lack of commonality among the projects in their respective goals and objectives. While many of the project's smart meters deployments covered more than 90 percent of their systems, some conducted pilot-scale deployments on less than 20 percent of their systems. And, for customer systems, some devices (e.g., direct load control [DLC] devices and PCTs) were deployed widely, while others (e.g., IHDs and smart appliances) were deployed in relatively small numbers for testing and evaluations. Because of these differences, it is not productive to aggregate and analyze data for projects with such starkly different sets of objectives.

A final challenge concerned differences in the level of experience and expertise among the SGIG utilities with AMI and customer systems. In many cases, the technologies and systems involved learning curves to determine how to optimize new functions and capabilities properly. Projects that were primarily interested in learning generated fewer grid and customer impacts.

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

[27] A subset of 10 SGIG utilities conducted Consumer Behavior Studies (CBS) that applied experimental designs and randomized samples to evaluate customer enrollments, retention, and response to time-based rates. DOE's SGIG-CBS website contains further information on these projects including project descriptions and analysis reports.

APPENDIX C.
Supporting Build Metrics Data

Build metrics data is provided in three tables: 1) customer device deployments; 2) smart meter deployments by customer type and features enabled, and advanced metering infrastructure (AMI) integration with other systems; and 3) deployment of customer programs and time-based rates that were enabled by AMI.

C.1. Customer Device Deployments (by Project)

Number	Project Name	Number of Customer Devices		
		IHD	DLC	PCT
1	Atlantic City Electric Company		32,090	11,692
2	Baltimore Gas and Electric Company		202,906	144,482
3	Burbank Water and Power	50		
4	CenterPoint Energy	504		
5	Central Lincoln Peoples Utility District	46		
6	City of Fort Collins Utilities, CO		1,710	2,347
7	City of Glendale Water and Power, CA	81		
8	City of Tallahassee, FL			54
9	City of Wadsworth, OH	73	124	1,164
10	Connecticut Municipal Electric Energy Cooperative		4	5
11	Denton County Electric Cooperative	5	9	8
12	Detroit Edison Company	871		805
13	Duke Energy Business Services LLC	46		
14	Entergy New Orleans, Inc.	2,049		270
15	FirstEnergy Service Corporation	720	37,721	553
16	Golden Spread Electric Cooperative		1,882	1,311
17	Idaho Power Company		133	
18	Iowa Association of Municipal Utilities		300	4,765
19	M2M Communications		512	
20	Marblehead Municipal Light Department		5	32
21	Minnesota Power		1,571	
22	New Hampshire Electric Cooperative, Inc.	343		
23	NV Energy, Inc.			1,015
24	Oklahoma Gas and Electric Company			28,668
25	PECO Energy Company	196	60	
26	Pepco (DC)		16,010	11,383
27	Pepco (MD)		100,177	51,710
28	Duke Energy (formerly Progress Energy)		4103	

Number	Project Name	Number of Customer Devices		
		IHD	DLC	PCT
29	Rappahannock Electric Cooperative		11,929	
30	Sacramento Municipal Utility District	4,209	903	919
31	Sioux Valley Energy	84		
32	South Kentucky Rural Electric Cooperative Corporation		1,585	
33	Southwest Transmission Cooperative	100		
34	Talquin Electric Cooperative, Inc.			1,000
35	Vermont Transco, LLC	1,091		

C.2. Smart Meter Deployment, Features, and AMI Integration (By Project)

#	Utility Name	Number of Smart Meters by Customer Class				Number of Smart Meters with Features Enabled				AMI Integration with:			
		Total (#)	Residential (#)	Commercial (#)	Industrial (#)	Remote Connect/ Disconnect Enabled (#)	Outage Reporting Enabled (#)	Voltage Monitoring Enabled (#)	Tamper Detection Enabled (#)	Billing System	CIS	OMS	DMS
1	Baltimore Gas and Electric Company	575,081	533,691	41,390		533,691			575,081	✓	✓		
2	Black Hills Energy	68,980	55,539	13,396	45	632	68,980	68,980	68,980	✓		✓	
3	Black Hills Corp./Colorado Electric Utility Company	44,920	37,410	7,270	240	840	44,920	44,920	44,920	✓	✓	✓	
4	Burbank Water and Power	51,928	45,243	6,483	202	45,150	51,835	51,835	51,835	✓	✓	✓	
5	CenterPoint Energy	2,130,737	1,859,008	271,729		2,038,499	2,130,737		2,130,737	✓	✓	✓	✓
6	Central Lincoln Peoples Utility District	38,620	37,380	1,175	65	37,380	38,620	38,620	38,620	✓	✓	✓	
7	Central Maine Power Company	622,380	557,269	62,546	2,565	576,394	622,380	622,380	622,380	✓	✓	✓	
8	Cheyenne Light, Fuel and Power Company	39,102	34,858	4,000	244	1,283	39,102	39,102	39,102	✓		✓	
9	City of Anaheim Public Utilities Department	7,167	7,167			6	7,167			✓	✓	✓	
10	City of Auburn, IN	7,474	6,318	1,054	102	2,754	7,474	7,474	7,474	✓	✓	✓	✓
11	City of Fort Collins Utilities, CO	84,454	75,610	8,809	35	84,304	15,723	15,723	84,454	✓	✓		
12	City of Fulton, MO	5,505	4,539	916	50	4,539	5,505			✓	✓	✓	
13	City of Glendale Water and Power, CA	85,582	73,871	11,370	341	85,582	85,582	85,582	85,582	✓	✓		

#	Utility Name	Number of Smart Meters by Customer Class				Number of Smart Meters with Features Enabled				AMI Integration with:			
		Total (#)	Residential (#)	Commercial (#)	Industrial (#)	Remote Connect/ Disconnect Enabled (#)	Outage Reporting Enabled (#)	Voltage Monitoring Enabled (#)	Tamper Detection Enabled (#)	Billing System	CIS	OMS	DMS
14	City of Leesburg, FL	16,683	14,428	2,255		14,559	16,683	16,683	16,683	✓	✓	✓	✓
15	City of Naperville, IL	58,930	54,042	4,866	22	54,042	58,663	4,866	58,663	✓	✓		
16	City of Ruston, LA	10,596	9,792	804		4,600	10,596	10,596	10,596	✓	✓		
17	City of Wadsworth, OH	12,600	11,111	942	547	12,053	12,600	12,600	12,600	✓	✓		
18	Cleco Power LLC	284,797	243,804	40,385	608	262,708			284,797				
19	Cobb Electric Membership Corporation	194,195	176,587	17,608		18,218	194,195	194,195	194,195	✓	✓		
20	Connecticut Municipal Electric Energy Cooperative	38,598	36,265	2,333		23,108	37,865	38,598	25,426	✓	✓	✓	
21	Denton County Electric Cooperative	179,818	165,784	11,718	2,316	168,195			179,818	✓	✓	✓	
22	Detroit Edison Company	688,717	636,571	52,146		636,571	688,717	688,717	688,717	✓	✓	✓	✓
23	Duke Energy Business Services LLC	1,062,169	766,006	289,285	6,878	1,062,169			473,537	✓	✓	✓	✓
24	Entergy New Orleans, Inc.	4,436	4,436							✓	✓		
25	Electric Power Board of Chattanooga, TN	175,116	152,450	22,584	82		175,116	175,116		✓	✓	✓	
26	FirstEnergy Service Corporation	34,309	31,260	3,049									
27	Florida Power and Light Company	3,068,136	2,931,873	134,592	1,671		3,072,318	3,072,318	3,072,318	✓	✓	✓	

#	Utility Name	Number of Smart Meters by Customer Class				Number of Smart Meters with Features Enabled				AMI Integration with:			
		Total (#)	Residential (#)	Commercial (#)	Industrial (#)	Remote Connect/ Disconnect Enabled (#)	Outage Reporting Enabled (#)	Voltage Monitoring Enabled (#)	Tamper Detection Enabled (#)	Billing System	CIS	OMS	DMS
28	Golden Spread Electric Cooperative	88,411	39,870	28,454	20,087	7,720	67,995	44,185	55,876	✓	✓	✓	✓
29	Guam Power Authority	50,233	43,538	6,695		43,538	50,233	50,233	50,233				
30	Idaho Power Company	380,928	312,892	68,036					406	✓	✓	✓	
31	Indianapolis Power and Light Company	10,275	3,817	6,408	50	10,275			10,275	✓	✓		
32	Iowa Association of Municipal Utilities	11,265	9,280	1,594	391		11,265	2,563	8,702	✓		✓	
33	Jacksonville Electric Authority	40,000	40,000			40,000	40,000			✓	✓	✓	
34	Knoxville Utilities Board	3,760	3,055	681	24	3,760	3,760		3,760	✓	✓	✓	
35	Lafayette Consolidated Government, LA	65,134	59,403	5,731		65,134				✓			
36	Lakeland Electric	121,900	109,415	12,389	96	11,502	121,900	121,900	121,900	✓	✓	✓	
37	Madison Gas and Electric Company	4,355	523	3,794	38				3,579				
38	Marblehead Municipal Light Department	10,215	9,796	419		134	10,215	10,215	10,215	✓	✓	✓	
39	Minnesota Power	8,030	7,843	187		1,571	8,030	8,030		✓	✓		
40	Modesto Irrigation District	3,538	3,220	318		3,220	3,538	3,538	3,220	✓			
41	Navajo Tribal Utility Authority	40,000	35,696	4,304		16,000	40,000		40,000	✓		✓	
42	New Hampshire Electric Cooperative	83,595	72,657	10,938		83,595	83,595	83,595	83,595	✓	✓	✓	
43	NV Energy	1,202,248	1,134,474	67,774		1,107,933	1,202,248	1,202,248	1,202,248	✓	✓		

#	Utility Name	Number of Smart Meters by Customer Class				Number of Smart Meters with Features Enabled				AMI Integration with:			
		Total (#)	Residential (#)	Commercial (#)	Industrial (#)	Remote Connect/ Disconnect Enabled (#)	Outage Reporting Enabled (#)	Voltage Monitoring Enabled (#)	Tamper Detection Enabled (#)	Billing System	CIS	OMS	DMS
44	Oklahoma Gas and Electric Company	818,415	706,502	102,699	9,214	736,178	818,415	818,415	818,415	✓	✓		
45	Pacific Northwest Generating Cooperative	97,281	84,852	11,134	1,295	6,416	74,407	47,459	68,453	✓	✓		
46	PECO Energy Company	784,253	766,966	17,287		784,253	784,253		784,253	✓	✓	✓	
47	Pepco (DC)	277,222	248,983	28,239		266,057	269,876	269,876	269,876		✓	✓	
48	Pepco (MD)	552,982	501,660	51,322		515,744	542,538	542,538	542,538		✓	✓	
49	Progress Energy Service Company (now Duke Energy)	130,315	18,063	108,650	3,602		72,048		58,267	✓	✓		
50	Rappahannock Electric Cooperative	51,068	45,006	5,951	111	12,479	51,068		51,068	✓	✓	✓	
51	Sacramento Municipal Utility District	617,502	574,277	43,225		574,277	617,502	617,502	617,502	✓	✓		
52	Salt River Project	458,742	396,227	62,515		458,742			458,742	✓	✓		
53	Sioux Valley Energy	27,641	25,740	531	1,370	710	27,641	27,641	27,641	✓	✓	✓	
54	South Kentucky Rural Electric Cooperative Corporation	66,247	61,559	4,143	545	13,850	66,247	66,247	66,247	✓	✓	✓	
55	South Mississippi Electric Power Association	224,757	207,900	16,763	94	34,875	143,932	33,384	143,193	✓	✓	✓	
56	Southwest Transmission Cooperative	59,745	52,047	7,521	177	4,713	23,958	35,787	35,787	✓	✓		
57	Stanton County Public Power District	2,293	2,027	266			2,293	2,293		✓	✓		

#	Utility Name	Number of Smart Meters by Customer Class				Number of Smart Meters with Features Enabled				AMI Integration with:			
		Total (#)	Residential (#)	Commercial (#)	Industrial (#)	Remote Connect/ Disconnect Enabled (#)	Outage Reporting Enabled (#)	Voltage Monitoring Enabled (#)	Tamper Detection Enabled (#)	Billing System	CIS	OMS	DMS
58	Talquin Electric Cooperative	54,945	54,022	923		54,945	54,945	54,945	54,945	✓	✓	✓	
59	Town of Danvers, MA	12,963	11,088	1,858	17	945	12,963	1,260	12,963	✓	✓		
60	Tri-State Electric Membership Corporation	15,156	14,564	592		2,064			15,156	✓			
61	Vermont Transco	305,464	263,869	40,150	1,445	245,249	25,985	33,555	135,586	✓	✓	✓	
62	Wellsboro Electric Company	4,792	3,770	1,014	8	49	4,792	4,792	4,792	✓	✓	✓	
63	Westar Energy	47,899	43,475	4,406	18	46,109	47,899		47,899	✓	✓	✓	
64	Woodruff Electric Cooperative	14,949	14,198	751		14,949	14,949	14,949	14,949	✓	✓		

C.3. Customer Programs and Rates Enabled by AMI (By Project)

#	Project Name	Web Portal		Prepay		Net Metering		Critical Peak Rebate		Time-of-Use		Critical Peak Pricing		Variable Pricing	
		Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)
1	Baltimore Gas and Electric Company	448,630	197,838					23,402	23,402						
2	Black Hills Energy	4,677	4,677												
3	Black Hills Corp./Colorado Electric Utility Company	1,783	1,783												
4	Burbank Water and Power	45,150	2,910							200	200				
5	CenterPoint Energy	2,344,905	18,798												
6	Central Lincoln Peoples Utility District	38,620	1,345												
7	Central Maine Power Company	580,743	26,521												
8	Cheyenne Light, Fuel and Power Company	2,271	2,271												
9	City of Auburn, IN	7,474	3,684							2	1				
10	City of Fort Collins Utilities, CO														
11	City of Glendale Water and Power, CA	73,871	926												

#	Project Name	Web Portal		Prepay		Net Metering		Critical Peak Rebate		Time-of-Use		Critical Peak Pricing		Variable Pricing	
		Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)
12	City of Leesburg, FL	14,428	20			16,683	10								
13	City of Naperville, IL					58262	3			20		20			
14	City of Ruston, LA	10,596	2	10,596	2	681	4								
15	City of Wadsworth, OH	1,361	1,361			12,600	3			12,600	143				
16	Cobb Electric Membership Corporation	194,195	4,770							194,195	4	194,195			
17	Connecticut Municipal Electric Energy Cooperative	26,159	26,159												
18	Detroit Edison Company	315,137	2,528	200	3							636,571	1,489		
19	Duke Energy Business Services	4,000,000	3,136,202			1,382	1,382								
20	Entergy New Orleans, Inc.	2,570	2,570												
21	Electric Power Board of Chattanooga, TN	174,336	139,478							5,000	130				
22	FirstEnergy Service Corporation	44,012	1,882												
23	Florida Power and Light Company	2,931,873	2,931,873												
24	Golden Spread Electric Cooperative	10,405	10,405	10,242	204										

#	Project Name	Web Portal		Prepay		Net Metering		Critical Peak Rebate		Time-of-Use		Critical Peak Pricing		Variable Pricing	
		Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)
25	Guam Power Authority	50,233	2,112												
27	Idaho Power Company	416,020	146,971							1,517	1,517				
28	Indianapolis Power and Light Company	470,000	8,899												
29	Iowa Association of Municipal Utilities	4,765	4,765												
30	Jacksonville Electric Authority	290,000	290,000	40,000	64										
32	Lafayette Consolidated Government, LA					651,134	115								
33	Lakeland Electric	121,900	3,705			121,900	92			121,900	3,589				
34	M2M Communications	96	96												
35	Marblehead Municipal Light Department	10,215	458												
36	Minnesota Power	3,644	901			8030									
37	Modesto Irrigation District	102,936	24,072												
39	New Hampshire Electric Cooperative									81,544	169	148	132		
40	NV Energy	1,181,872	471,789							73,603	1,877	121,976	3,199		

#	Project Name	Web Portal		Prepay		Net Metering		Critical Peak Rebate		Time-of-Use		Critical Peak Pricing		Variable Pricing	
		Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)
41	Oklahoma Gas and Electric Company	843,914	61,097							843,914	38,997	1,536	1,536	843,914	37,461
42	Pacific Northwest Generating Cooperative	80,799	37,494												
43	PECO Energy Company	784,253	238,988			773,184	1,636								
44	Pepco (DC)	260,280	14,093												
45	Pepco (MD)	517,943	25,925												
46	Progress Energy Service Company (now Duke Energy)			137,096											
47	Rappahannock Electric Cooperative		786												
48	Sacramento Municipal Utility District	137,244	26,332							44,348	4,861	55,571	721		
49	Salt River Project	458,742	155,977												
50	Sioux Valley Energy	27,641	5,411			27,858	24								
51	South Kentucky Rural Electric Cooperative Corporation	66,247	66,247			64,662	3								
52	South Mississippi Electric Power Association	167,780	73,229	26,657	323					80,030	11,850				

#	Project Name	Web Portal		Prepay		Net Metering		Critical Peak Rebate		Time-of-Use		Critical Peak Pricing		Variable Pricing	
		Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)	Customers with Access (#)	Customers Enrolled (#)
54	Talquin Electric Cooperative	All	18,000												
55	Town of Danvers, MA	13,064	4,725			2	2								
56	Tri-State Electric Membership Corporation	15,156	947	15,156	810										
57	Vermont Transco	275,995	24,334							10,737	3				
58	Wellsboro Electric Company	4,792	4,792												
59	Westar Energy	47,899	20,187							1,000	9				

APPENDIX D.
Supporting Impact Metrics Data

Individual utilities reported impact metrics for key data points, which are anonymized and included in the following table.

D.1. Avoided Vehicle Miles, Truck Rolls, and O&M Costs (By Project)

Number	Avoided Meter Operations Vehicle Miles	Avoided Meter Operations Truck Rolls (#)	Avoided Meter Operations O&M Costs ($)
1		70,440	$14,742,033
2		29,306	
3		41,230	
4		41,850	
5		872,520	
6		403,224	
7		41,224	
8	2,655	927	$8,408
9		9,686	
10	17,700	9,200	
11		4,630	$335,545
12		351,632	
13		21,622	$6,677,973
14		133,085	
15	8,085,131	747,430	$174,401,000
16		17,901	
17	638,872	3,901,896	$2,632,808
18	3,508,331		$6,503,758
19	892,621	47,338	$3,360,451
20	116,917	56,215	
21	3,069,871	9,471	$12,177,585
22	908	583	$6,426
23	531,684	196,920	$2,264,580
24	1,728	216	
25	35,550	1,185	$443,732
26	147,666	17,477	
27	4,383	1,961	
28	48,190,330	2,601,899	$53,964,319
29		1,318,455	$35,810,495

Number	Avoided Meter Operations Vehicle Miles	Avoided Meter Operations Truck Rolls (#)	Avoided Meter Operations O&M Costs ($)
30		122,129	
31	632,371	1,144	$758,836
32		1,119,590	
33		1,067,468	
34		1,370	
35	838,176	131,864	$812,265
36	1,377,942	247,658	
37	94,319	23,143	$743,777
38		380	
39		50,402	
40		6,082	
41		27,203	
42	13,444	620	$18,037
43	173,696	37,132	$480,576

APPENDIX E.
Acronyms and Abbreviations

Abbreviation	Definition
AC	alternating current
AMI	advanced metering infrastructure
AMR	automated meter reading
ARRA	American Recovery and Reinvestment Act
BGE	Baltimore Gas & Electric
BWP	Burbank Water and Power
CBS	Consumer Behavior Studies
CIS	customer information system
CMEEC	Connecticut Municipal Electric Energy Cooperative
CMP	Central Maine Power
CPP	critical peak pricing
CPR	critical peak rebate
CVR	conservation voltage reduction
DA	distribution automation
DER	distributed energy resource
DERMS	distributed energy resource management system
DLC	direct load control
DMS	distribution management system
DOE	U.S. Department of Energy
DSM	demand-side management
EPB	Electric Power Board of Chattanooga
EV	electric vehicle
FPL	Florida Power and Light
GIS	geographic information systems
GU	Groton Utilities
GWP	Glendale Water and Power
HAN	home-area networks
IHD	in-home display
IOU	investor-owned utility
MBRP	Metrics and Benefits Reporting Plans
MDMS	meter data management system

Abbreviation	Definition
NIST	National Institute of Standards and Technology
NISTIR	NIST Interagency Report
O&M	operations and maintenance
OG&E	Oklahoma Gas and Electric
OMG	outage management system
OMS	outage management system
PCT	programmable communicating thermostat
PNGC	Pacific Northwest Generating Cooperative
R&D	research and development
SGIG	Smart Grid Investment Grant
SMUD	Sacramento Municipal Utility District
SVE	Sioux Valley Energy
TEC	Talquin Electric Cooperative
TOU	time-of-use
VAR	volt-ampere reactive
VPP	variable peak pricing
WMS	workforce management system