U.S. DEPARTMENT OF ENERGY

Electricity Delivery & Energy Reliability

American Recovery and Reinvestment Act of 2009

Operations and Maintenance Savings from Advanced Metering Infrastructure – Initial Results

Smart Grid Investment Grant Program

December 2012

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RECOVERY ACT SMART GRID PROGRAMS

Table of Contents

Executive Summary

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

Of the 99 SGIG projects, 63 are installing advanced metering infrastructure (AMI) to improve operational efficiencies and support billing and customer services. In general, the SGIG AMI projects seek to achieve one or more of the following objectives: (1) reduce meter operations costs, (2) reduce vehicle miles, emissions and fuel consumption, and (3) improve operations to support customer requests.

Achieving these AMI objectives result in the following benefits:

- More efficient utility operations, lower costs of electricity, and more opportunities to keep rates affordable
- Reduced environmental emissions from smaller vehicle fleets and reduced truck rolls and fuel consumption
- Improved customer services and greater levels of customer participation and satisfaction

This report presents information about the SGIG AMI projects including the devices and systems being implemented, deployment progress, expected benefits, and initial results. The report also discusses the new capabilities being implemented including remote meter reading, remote service connections/disconnections (switching), meter tamper detection, outage detection and notification, and voltage and power quality monitoring.

Many of the SGIG AMI projects have not finished integrating smart meters with billing and other enterprise systems. Fifteen of the projects have reported initial results to DOE-OE based on operational experiences for a one year period from April 1, 2011 to March 31, 2012. These projects represent more than 3.5 million operating smart meters and have implemented automated meter reading and other functions for all of them.

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

Analysis of Initial Results

Table ES-1 provides a summary of the initial results from the 15 projects. The table shows a range of percentage change improvements across the projects from operation of AMI for four metrics: meter operations costs, vehicle miles driven, vehicle fuel consumption, and vehicle emissions. Meter reading costs alone can range from 1% to 4% of a utility's total distribution operations and maintenance costs.[2]

Meter O&M Savings Metrics	Range of % Improvements
Change in meter operations cost	-13% to -77%
Change in vehicle miles driven, fuel consumption, and CO_2 emissions	-12% to -59%

Table ES-1. Initial Results from AMI Operations for 15 SGIG Projects

Observations

The initial results are based on about one-quarter of the total number of SGIG AMI projects. Improvements were observed for all four metrics but there was variation in the results across the 15 projects. The variations were the result of several factors, including differences in legacy metering systems, meter operations practices, and the sizes and geographies of the service territories. Further analysis of more projects and time periods is needed before the root causes of the variations can be more completely understood. Observations from the initial results include:

- Cost reductions and productivity improvements observed to date are primarily related to reductions in labor and vehicle costs from remote meter reading, and automation of other billing-related services.
- Projects that have completed deployment of their AMI systems generally observed larger cost reductions than those that have not yet completed deployment.
- Of the projects that have completed deployment, the ones with lower customer densities per distribution line-mile observed larger savings per customer served than those with higher customer densities.

[2] Navigant Consulting, Inc. "Analysis of FERC Financial Report, FERC Form No. 1: Annual Report of Major Electric Utilities, 2007 to 2011." Analysis Memorandum to the U.S. Department of Energy, October, 2012.

- Several of the projects had prior experience with the deployment of AMI and its integration with legacy systems. Having previous experience has been beneficial for these projects in getting AMI to operate properly and with a minimum amount of delay, including having fewer customer and systems integration issues.

Next Steps

While all of the 63 AMI projects will ultimately have important information and findings to share, DOE-OE analysis will focus on the ones that are most able to provide quantitative results.[3] In the next year, more projects will be assessing operational changes and efficiency improvements from AMI. DOE-OE plans to present additional results in the future and more completely elaborate on the type and magnitude of benefits resulting from improved operational efficiency due to the application of AMI. This includes improvements in customer services. In the meantime, updates on deployment progress and case studies highlighting project examples are posted regularly on www.smartgrid.gov.

[3] Two of the AMI capabilities – outage detection and notification and voltage monitoring – are included in separate SGIG analysis reports on distribution reliability and voltage optimization, respectively.

1. Introduction

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

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

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

1.1 Purpose and Scope

This analysis report provides initial results from the 63 SGIG projects that are implementing advanced metering infrastructure (AMI) to achieve one or more of the following objectives: (1) reduce meter operations costs, (2) reduce vehicle miles, fuel consumption, and emissions, and (3) improve operations to support customer service and other distribution system functions.

The SGIG AMI projects report operational impacts to DOE-OE every six months. The operational impacts include data collection and analysis of four metrics: meter operations costs, vehicle miles driven, vehicle fuel consumption, and vehicle emissions. Fifteen of the 63 projects reported quantitative impacts covering a one year period from April 1, 2011 to March 31, 2012.

The reported impacts were calculated by the projects in two ways: (1) estimating the differences between baseline levels and measured conditions, and (2) estimating avoided costs

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

from AMI activities. Baselines were developed by the projects based on historical cost and operating data, and typically involved three year periods.

The initial analysis focuses on the impacts from automated meter reading and remote service switching. Impacts from AMI functions such as outage detection and notification, voltage monitoring, and those that enable time-based rate and other demand-side programs are addressed in other SGIG analysis reports.[5]

1.2 Organization of this Report

Section 2 of this report presents information about the devices, systems, and smart meter functions that the 63 SGIG AMI projects are deploying and their expected benefits. Section 3 summarizes what the projects are doing and their deployment progress as of June 30, 2012. Section 4 provides a summary of the initial results from the 15 projects that have implemented AMI and have observed changes in operational costs. Appendix A provides a list of the 63 projects and identifies the devices and systems that each are deploying as well as the capabilities they intend to implement.

[5] See three reports: (1) DOE-OE, *Reliability Improvements from Distribution Automation Technologies – Initial Results*. Smart Grid Investment Grant Program. October 2012; (2) DOE-OE, *Application of Automated Controls for Voltage and Volt-Ampere Reactive (VAR) Optimization – Initial Results*. Smart Grid Investment Grant Program. October 2012; (3) DOE-OE, *Demand Reductions from Application of Advanced Metering Infrastructure, Pricing Programs, and Customer Systems – Initial Results*. Smart Grid Investment Grant Program. October 2012.

2. Overview of Devices, Systems, and Expected Benefits

Traditionally, electric meters have been mechanical devices installed on customer premises that measure electricity consumption primarily for billing purposes. Traditional metering operations involve basic functions such as meter reading, connecting and disconnecting (switching) service, and supporting customer billing requests. Many of these functions have been performed manually and typically involved sending service trucks to meter locations.

The meter reading function involves several types of activities: on-cycle readings, off-cycle readings, and special requests. Traditionally, on-cycle readings occur monthly while off-cycle readings typically occur as a result of service switching, or in response to customer requests, and may occur at any time during the billing cycle.

With the advent of lower cost electronic meters and information and telecommunications systems, it has become possible to automate many of these functions. Before AMI, some utilities used automated meter reading (AMR) systems, which involve electronic meters and one-way communications to eliminate the need for manual meter reads. AMI introduces two-way communications and enables new opportunities for operational efficiency improvements.

AMI investments include the costs for new meters, communications networks, and information systems, as well as the efforts required for systems integration and workforce training. The transition from mechanical, manually-read meters to AMR and AMI systems has been an evolutionary process for the electric power industry and has been underway over the last several decades. Because of differences in utilities, cost structures, and service territories there is no single way to accomplish this transition and utilities have made investments in new systems at their own pace subject to local conditions and regulatory requirements.

2.1 Legacy Systems and AMI

As discussed, before AMI, utilities either read meters manually or used AMR systems. AMR systems use one-way communications, typically radio frequency (RF) or power line carrier (PLC), to transmit monthly usage information to utility billing systems. RF systems include both fixed locations and mobile “drive-by” systems involving meter reading vehicles.

Those utilities that have implemented AMR systems over the last several decades, have already gained operational savings from fewer manual meter reads and truck rolls for service calls. As a result, implementation of AMR affects the amount of operational savings that can be achieved from the transition to investments in AMI. In addition, in some cases, when AMR systems are not fully depreciated when the transition to AMI occurs, the asset values have to be written off if the AMR systems have not reached the end of their useful economic lives.

AMI differs from AMR in several respects. AMI involves smart meters, two-way communication networks, data management systems, and the ability to collect, transmit, and store electricity consumption and voltage data at various time intervals including 5, 15, and 60 minutes. Information systems are major components of AMI and are implemented by utilities to use data from the smart meters for various purposes including demand-side programs, customer systems, outage management, and distribution system management.

2.2 Communication Systems for AMI

Head-end systems (HES) are essential components of AMI communications networks. The function of HES is to manage data communications between smart meters and other information systems including meter data management systems, customer information systems, outage management systems, and distribution management systems. The HES transmits and receives data, sends operational commands to smart meters, and stores interval load data from the smart meters to support customer billing.

There is no standard approach or configuration for communications networks for supporting AMI operations. Utilities typically customize their own systems, which often consist of combinations of approaches and involve both legacy and new systems. In addition, many utilities use common communications platforms to support multiple field devices including distribution automation equipment, smart meters, and customer systems. For example, fiber backhaul and wireless radio networks may use one protocol to support communications for automated feeder switching and another for smart metering.

The selection of communications technologies depends on functional requirements, service territory topologies, and premise characteristics. While communication networks vary, they all share several fundamental elements. For example, AMI communication systems generally consist of multiple or tiered networks that use a combination of wired and wireless communications mechanisms. Utilities employ different configurations of the technologies to ensure they are able to provide reliable smart meter and customer system capabilities for their service territories. Table 1 lists the different types of communication technologies used to support AMI and meter communications.

Most utilities use two-layer systems to communicate between HES 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, BPL, microwave, and RF-cellular systems for backhauling large volumes of data. Some utilities use existing supervisory control and data acquisition (SCADA) communications systems to

Wired	Wireless
Fiber optic	Satellite
Broadband over power line (BPL)	Radio frequency (RF) – mesh network
Telephone dial-up modem	RF – Point to multipoint
Power line carrier (PLC)	RF – Microwave
Digital subscriber line (DSL)	RF – Cellular

Table 1. Examples of AMI Communications Technologies

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.

2.3 Information Systems for AMI

To operate AMI systems effectively, and leverage the full suite of smart meter functions, utilities integrate smart meters and communications networks with various types of information systems that serve a variety of purposes. For example, information systems that use smart meter data to support a variety of utility operations include:

- **Meter Data Management Systems** (MDMS), which process and store interval load data for billing systems, web portals, and other information systems..
- **Customer Information Systems** (CIS), which process data from MDMS and connect with billing systems for warehousing data on customer locations, demographics, contact information, and billing histories.
- **Outage Management Systems** (OMS), which process data about meter on/off status to pinpoint outage locations and often connect with geographic information systems (GIS) for dispatching repair crews and managing the restoration of services.
- **Distribution Management Systems** (DMS), which process data on outages and customer voltage levels for implementing electric reliability and voltage and volt-ampere reactive optimization procedures.

Information systems integration is a necessary and ongoing process for all utilities involved in AMI deployment. Legacy billing, CIS, OMS, and DMS were not designed to handle large volumes of interval load data from smart meters. For example, these data support time-based rate programs and web portals that provide customized “dashboards” for customers to manage electricity consumption and costs. Outage data from smart meters is made more valuable to grid operators when it is integrated with GIS and data from customer call centers, and with DMS.

The successful integration of smart meters, communications networks, and all of these information systems provide utilities with capabilities for significantly improving the efficiency of grid operations. Interval load data from smart meters provide benefits beyond those discussed above. For example, this information can be used for load research and forecasting to understand consumption patterns, the effects of demand-side programs, and how those effects relate to time-of-day, weather, and seasonal changes.

2.4 Smart Meter Functions

As discussed, in producing savings and efficiency improvements, the automation of meter operations involves several functions:

- **Remote meter reading** is the capability to communicate with meters and upload information on the amount of electricity consumed for time periods that can range from monthly to 5-minute intervals. In addition to regularly scheduled readings, smart meters also give utilities the capability to perform readings on-demand to address billing and other customer issues.
- **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.
- **Tamper detection and notification** is the capability to detect and notify utilities about tampering and electricity theft. Historically, electricity theft was identified by meter readers or headquarters personnel who identified abnormal changes in electricity usage over long periods of time.
- **Outage detection and notification** is the capability to transmit a "last gasp" notification when power to the meter is lost. 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 HES 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.
- **Voltage and power quality (PQ) monitoring** is the capability to measure voltage levels and certain power quality parameters. 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 diagnosis 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. In addition, smart meters can provide data to help utilities optimize voltage levels on distribution feeders.

2.5 Expected Benefits

Expected benefits from AMI operations include monetary savings and reductions in environmental emissions from efficiency and productivity improvements. These benefits involve changes in day-to-day workflow, logistics, and business processes for: (1) corporate operations and (2) field operations. Corporate operations include back-office functions for resource planning and forecasting, billing, and customer information systems and services. Field operations include meter reading, truck rolls for customer service calls, and maintenance of service vehicle fleets.

Because of differences in the objectives of the SGIG AMI projects, utility service territories, and business models, it is expected that the range of measured operating impacts and benefits from AMI will vary. One of the most important considerations is the ability to integrate large volumes of smart meter data for making these operational improvements. Realizing the benefits typically involve investments in smart meters, communications networks, information systems, and workforce training programs.

Corporate Operational Benefits

Corporate operational benefits are realized over time as utilities integrate smart meter data into their business practices. Smart meter data on electricity consumption patterns by time-of-day can improve load research and forecasting functions and enable better planning of loads and resources. Tamper and theft capabilities can reduce the magnitude of these problems and thus reduce a utility’s overall costs of operations.

More efficient and better customer services are also important benefits. This includes faster response to billing requests and issues, as well as greater opportunities for utilities to offer customer-facing programs including web portals and time-based rates (e.g., time-of-use and critical peak pricing rates). Smart meters improve services by reducing the number of touch points and the time it takes to provide customers with the information they need to resolve issues. In many cases, customer questions or complaints can be resolved during initial requests without requiring follow up calls or the need to dispatch field crews.

Field Operational Benefits

Meter operations incur many costs, but those most directly impacted by AMI can be split into two categories: labor and vehicle operations. Utilities deploying smart meters for automated meter reading and service switching expect operational savings by reducing the frequency and duration of tasks completed in the field. In some cases, metering tasks may be completed automatically or shifted to lower cost resources. Utilities with numerous vehicles dedicated to meter operations can also reduce the size of their vehicle fleets.

Reductions in the number of vehicles dispatched and the number of vehicle miles traveled also result in reductions in the amount of fuel consumed for these avoided trips. Lower fuel consumption leads to lower environmental emissions, including reductions in carbon dioxide.

3. SGIG AMI Projects and Deployment Progress

The 63 SGIG AMI projects are listed in Table 2. Appendix A provides further information on each of the projects.

Electric Cooperatives	Public Power Utilities	Investor-Owned Utilities
• Cobb Electric Membership Corporation, Georgia • Connecticut Municipal Electric Energy Cooperative, Connecticut • Denton County Electric Cooperative, Texas • Golden Spread Electric Cooperative, Inc., Texas • New Hampshire Electric Cooperative, Inc., New Hampshire • Pacific Northwest Generating Cooperative, Washington • Rappahannock Electric Cooperative, Virginia • Sioux Valley Southwestern Electric Cooperative Inc., Minnesota, South Dakota • South Kentucky Rural Electric Cooperative Corporation, Kentucky • South Mississippi Electric Power Association, Mississippi • Southwest Transmission Cooperative, Inc, Arizona • Talquin Electric Cooperative, Florida • Tri-State Electric Membership Corporation, Georgia, North Carolina, Tennessee • Vermont Transco, LLC, Vermont • Wellsboro Electric Company, Pennsylvania • Woodruff Electric Cooperative, Arkansas	• Burbank Water and Power, California • Central Lincoln People's Utility District, Oregon • City of Anaheim, California • City of Auburn, Indiana • City of Fort Collins Utilities, Colorado • City of Fulton, Missouri • City of Glendale, California • City of Leesburg, Florida • City of Naperville, Illinois • City of Ruston, Louisiana • City of Wadsworth, Ohio • EPB, Georgia, Tennessee • Guam Power Authority, Guam • Iowa Association of Municipal Utilities, Iowa • Knoxville Utilities Board, Tennessee • Lafayette Consolidated Government, Louisiana • Lakeland Electric, Florida • Marblehead Municipal Light Department, Massachusetts • Modesto Irrigation District, California • Navajo Tribal Utility Authority, Arizona, New Mexico, Utah • Sacramento Municipal Utility District, California • Salt River Project Agricultural Improvement and Power District, Arizona • Stanton County Public Power District, Nebraska • Town of Danvers, Massachusetts	• Baltimore Gas and Electric Company, Maryland • Black Hills/Colorado Electric Utility Company, Colorado • Black Hills Power, South Dakota, Wyoming • CenterPoint Energy, Texas • Central Maine Power Company, Maine • Cheyenne Light, Fuel and Power Company, Wyoming • Cleco Power LLC, Louisiana • Detroit Edison Company, Michigan • Duke Energy Business Services LLC, Indiana, Kentucky, Ohio, North Carolina, South Carolina • FirstEnergy Service Corporation, Ohio, Pennsylvania • Florida Power & Light Company, Florida • Idaho Power Company, Idaho, Oregon • Indianapolis Power and Light Company, Indiana • Jacksonville Electric Authority, Florida • Madison Gas and Electric Company, Wisconsin • Minnesota Power (Allete), Minnesota • NV Energy, Inc., Nevada • Oklahoma Gas & Electric, Oklahoma • PECO, Pennsylvania • Potomac Electric Power Company, District of Columbia • Potomac Electric Power Company, Maryland • Progress Energy Service Company, Florida, North Carolina, South Carolina • Westar Energy, Inc., Kansas

Table 2. SGIG AMI Projects

Figure 1 shows the number of the 63 projects that are deploying smart meters with the capabilities to support the five primary functions for improving meter operations. As shown, the vast majority of the projects (90%) are interesting in using (now or sometime in the future) all five functions.

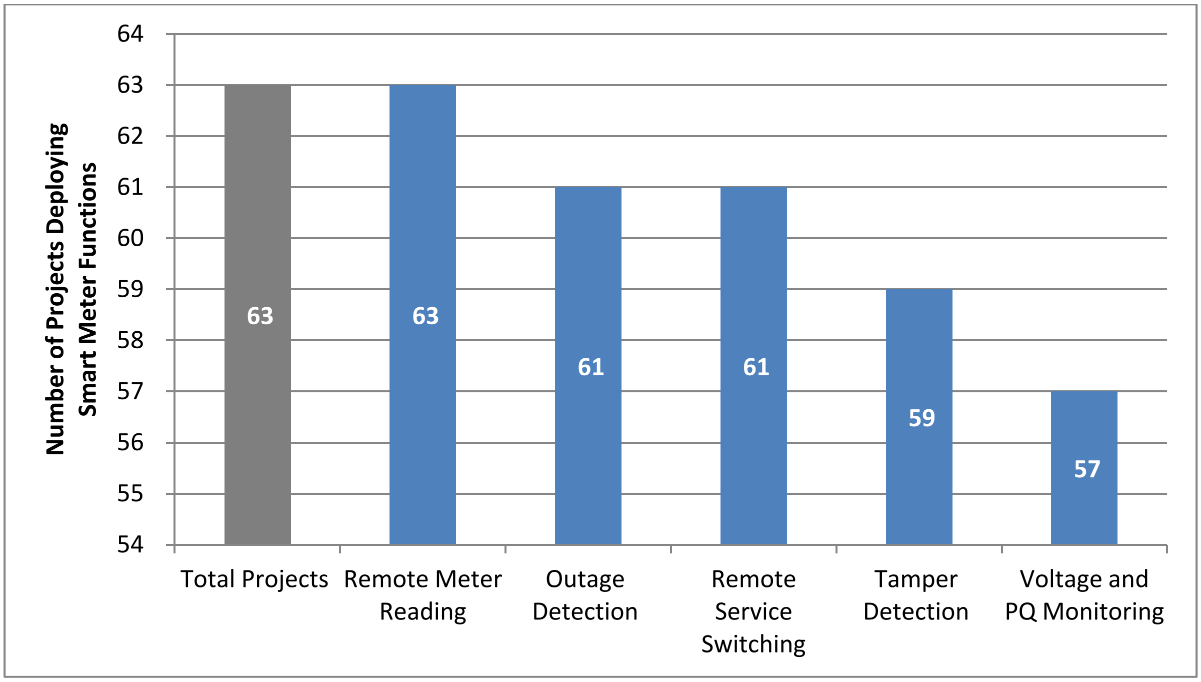

Figure 1. SGIG AMI Projects and the Smart Meter Functions

Figure 2 shows the number of the 63 projects that are integrating smart meter data with the major types of information systems. As shown, while most of the projects are integrating smart meters with billing systems and CIS, about half of the projects are integrating outage management and distribution management systems. This indicates that many of the projects are developing the capabilities for using smart meter data to support outage and voltage management but are not planning to move ahead with those activities right away.

3.1 Deployment Progress

Currently, most of the projects are in the process of installing equipment, integrating information systems, and starting AMI operations. Figure 3 shows the extent of smart meter deployments as of June 30, 2012 and that 34 of the project have completed at least 76% of planned installations. Eight recipients have already completed deployment, seven have experienced delays and have yet to start, and the rest of the projects are in various stages of the process. There are many factors that account for the variation in the pace of meter installations including project schedules, equipment delivery schedules, and systems integration issues.

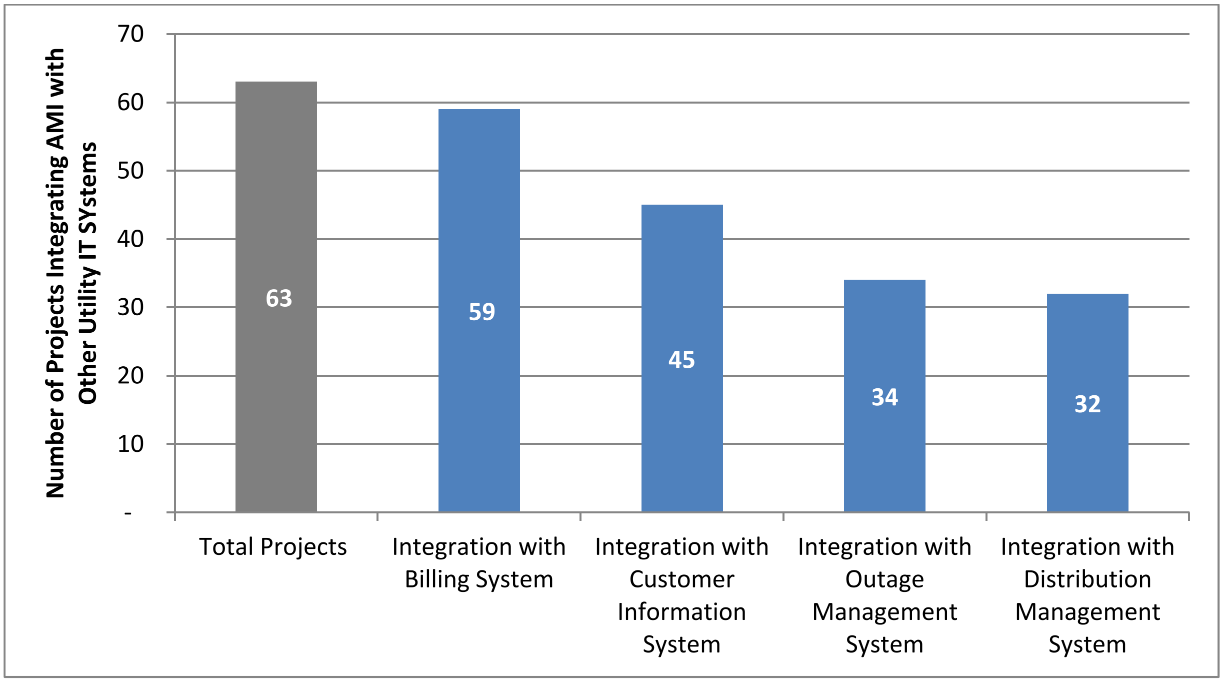

Figure 2. SGIG AMI Projects and Integration with Information Systems

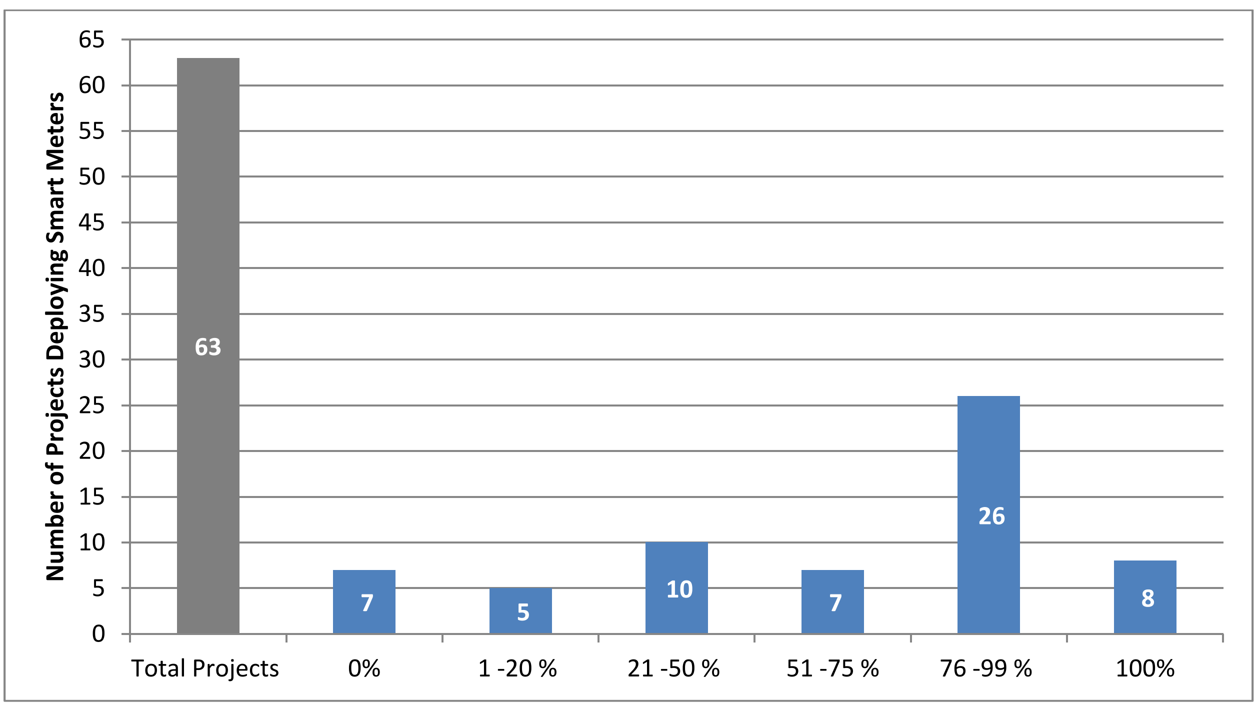

Figure 3. Progress with Deploying AMI Smart Meters

3.2 SGIG AMI Project Examples

The following examples illustrate how different projects are accomplishing operational savings objectives.

Detroit Edison (DECo)

Headquartered in Detroit, Michigan, DECo serves approximately 2,100,000 customers and manages approximately 3,271 distribution feeders and 716 substations. DECo is pursuing meter operations cost reductions by implementing smart meters to remotely: (1) read meters, (2) diagnose voltage and power quality conditions, (3) connect and disconnect service, (4) identify electricity theft, and (5) identify and detect outages.

DECo has installed a multi-tier communications network to support AMI and customer systems. Other dedicated communication networks, using fiber optic, microwave, and RF technologies, operate in parallel to support distribution automation. Home area networks in the project consist of wireless radio frequency (RF) to communicate between customer systems and meters. RF mesh is used to network meters and transmit data to collectors which use wireless and cellular backhaul networks. The AMI system is integrated with MDMS and CIS to support billing, web portals, and time-based rate programs. Data are also being integrated with OMS to support analysis of outage and restoration notifications and to ping meters to determine the extent of power outages.

DECo is encouraging retail competition among electricity suppliers and this creates possibilities for switching customers among the suppliers which requires accurate and timely meter readings for smooth transactions, billings, and settlements. AMI helps to facilitate this process through remote meter reading and service switching services.

DECo is replacing approximately 625,000 meters that were read by meter readers using handheld devices. The operational benefits are intended to exceed the capital and operating costs of the new AMI system, including systems integration requirements. The majority of operational benefits are expected from remote meter reading and remote service switching. One of the objectives of the project is to mitigate the impact of an aging workforce and enables meter readers to retire or transition to other parts of the utility and/or receive training for higher value work assignments.

Sacramento Municipal Utility District (SMUD)

Headquartered in Sacramento, California, SMUD serves approximately 600,000 customers involving approximately 610 distribution feeders and 234 substation transformers and associated switchgear. SMUD is pursuing meter operations improvements and cost reductions by implementing smart meter functions to remotely: (1) read meters, (2) diagnose voltage and power quality conditions, (3) connect and disconnect service, (4) identify and detect outages, and (5) identify electricity theft.

SMUD has installed a multi-tier communications network to operate the AMI system and enable the smart meter functions listed above. A RF mesh network is used to communicate data, notifications, and commands between meters. Wide area networks backhaul data to the HES using wireless telecommunications carriers.

AMI is integrated with MDMS and CIS to enable customer web portals, resolve billing issues, and respond to customer requests. The integration of smart meter functions and utility systems enables SMUD to automate many metering and back office tasks and reduce the number of touch points and time needed to complete customer transactions. Additional operational efficiencies are gained by using the two-way communication network to remotely diagnose meter conditions, resolve service issues, and update meter parameters for new customer programs. SMUD also provides higher levels of customer service by providing information and resolving problems in shorter periods of time.

SMUD is replacing approximately 620,000 meters that require field resources to read meters and switch service. The operational benefits are intended to exceed the capital and operating costs of the AMI system. SMUD is offering training and new job opportunities to nearly all of the affected meter readers and other staff members have made transitions to other jobs within the utility.

South Kentucky Rural Electric Cooperative Corporation (SKRECC)

Headquartered in Somerset, Kentucky, SKRECC serves approximately 66,600 customers and manages approximately 40 substations and 140 distribution feeders. SKRECC is pursuing meter operations improvements and cost reductions by implementing smart meter functions to remotely: (1) read meters, (2) diagnose voltage and power quality conditions, (3) connect and disconnect service, (4) identify electricity theft, and (5) detect outages.

SKRECC has installed a PLC network to support AMI systems and enable the smart meter capabilities listed above. PLC is used to network meters and DSL subscriber lines and backhaul data from substations to the AMI system at the utility.

AMI is integrated with MDMS and CIS to enable the development of web portals and time-based rate programs. The capabilities from the integration of these systems improve SKRECC's ability to respond to customer requests more efficiently. Information related to outages and power quality issues can be used by distribution operators and line crews to improve reliability and service.

SKRECC is replacing 68,000 meters[6] that require resources for reading and servicing by contractors using handheld devices. The operational benefits of the project are intended to exceed the capital and operating costs of the AMI system.

[6] There are SKRECC customers who have multiple accounts which is why the number of meter replacements exceeds the number of customers served.

4. Analysis of Initial Results

This section presents analysis of the 15 SGIG AMI projects that reported initial results to DOE-OE and observed changes in meter operations. The 15 projects represent 3.7 million smart meters that were installed and operational during the impact reporting period.

The analysis results include changes in meter operations costs and vehicle miles resulting from the implementation of AMI and smart meter functions. The changes in performance were observed over a one-year period from April 1, 2011 to March 31, 2012. The changes were based on: (1) the differences between baseline forecasts and measured conditions, or (2) meter related costs and operations that were avoided due to the automation or remote operations.[7]

Figures 4 and 5 provide information about the 15 projects that reported impacts. Figure 4 provides a breakdown of the metering functions that are covered and shows that almost three-quarters of the projects are implementing all of the functions. Figure 5 shows that 13 projects are replacing manual metering reading systems and 3 are replacing AMR systems.

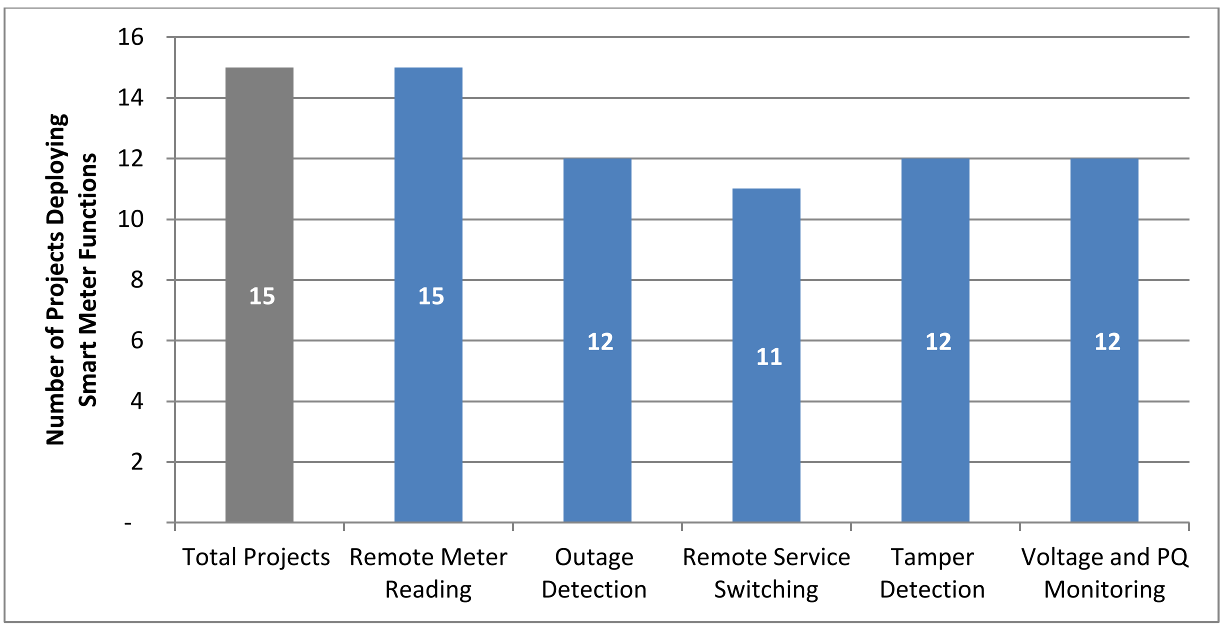

Figure 4. SGIG AMI Projects Reporting Results with Smart Meter Functions as of June 30, 2012

[7] While fuel usage and vehicle emissions are not directly measured by the projects, DOE-OE calculates these metrics based on the vehicle miles avoided, vehicle type, and average fuel efficiency. Emission output and fuel usage coefficients were derived from Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) Model (http://greet.es.anl.gov/).

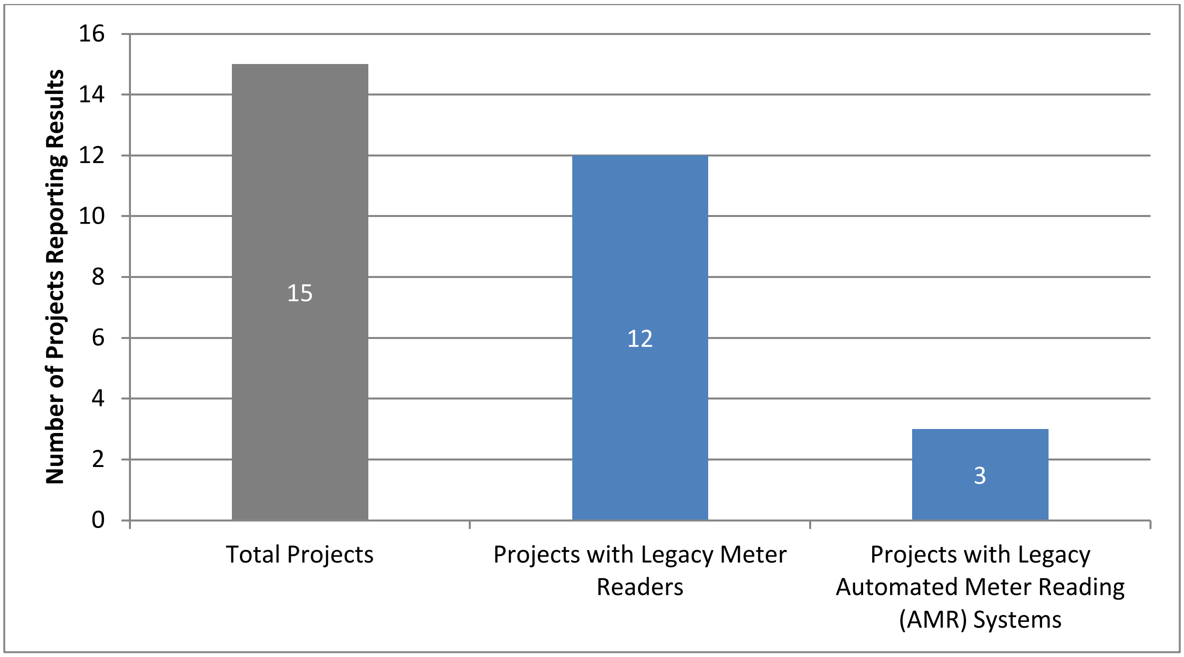

Figure 5. Number of Projects Reporting Results by Type of Legacy Metering System

4.1 Summary of Results

Table 3 provides the initial results of the impacts from the implementation of AMI for operational savings. The table provides a range of results for the 15 projects representing the lowest and highest of the observed changes. The results show measurable operational savings from automation of metering services tasks and reductions in the number of labor-hours and truck rolls.

Meter Operations Impact Metrics	% Change in Improvement
Change in meter operations cost	-13% to -77%
Change in vehicle miles driven, vehicle fuel consumption, and CO_2 emissions	-12% to -59%

Table 3. Initial Results from AMI Operations for 15 SGIG Projects (April 2011–March 2012)

Figure 6 shows the initial results from AMI operations for the 15 projects. The projects include 8 electric cooperatives, 7 investor-owned utilities, and 2 public power utilities. In this group, the electric cooperatives tend to have lower customer densities, while the public power utilities tend to have higher customer densities.

The 7 projects in the “blue oval” had completed deployment of their AMI systems, while the 8 projects in the “gray oval” had yet to complete deployment of their AMI systems. The projects with incomplete AMI deployments were in the process of integrating systems and implementing the various metering functions, but not all of the intended functions were operational during the reporting period.

The figure shows that the projects that completed deployment observed relatively larger impacts in terms of reductions in meter operations costs per customer than those that had not yet completed deployment. For the completed projects, those with lower customer densities tended to observe larger impacts than those with relatively higher customer densities.

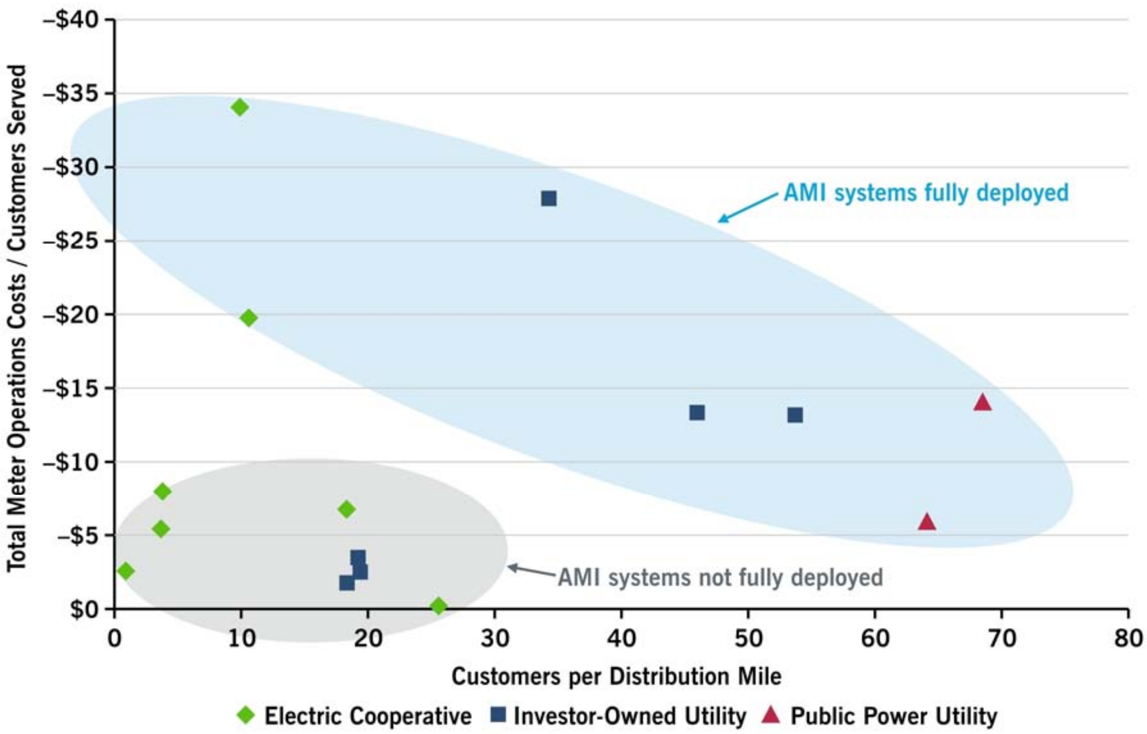

Figure 6. Project-Level Changes in Meter Operations Costs (April 2011–March 2012)

4.2 Summary of Observations

Observations from the initial results include:

- Cost reductions and productivity improvements observed to date are primarily related to reductions in labor and vehicle costs from remote meter reading, and automation of other billing-related services.

- Of the projects that have completed deployment, the ones with lower customer densities per distribution line-mile observed larger savings per customer served than those with higher customer densities.
- Several of the projects had prior experience with the deployment of AMI and its integration with legacy systems. Having previous experience has been beneficial for these projects in getting AMI to operate properly and with a minimum amount of delay, including having fewer customer and systems integration issues.

Investments in AMI involve “learning periods” during which utility headquarters staff members and field crews become acquainted with the functions of AMI to improve meter operations, resolve problems with communications networks, accomplish integration with various back-office information systems, and develop needed skill sets and competencies. Many of the projects are undertaking staff training programs and developing tools and techniques for smart meter data analytics and visualization, particularly in new areas such as electricity theft detection and for applications outside of AMI for operational savings such as outage detection and notification and voltage level monitoring. Over time, DOE-OE expects that the projects will use the AMI data to improve operational efficiency across many functions, including customer service operations, load research and forecasting, and verification of results from time-based rate and other demand-side programs.

5. Next Steps

The analysis has focused so far on changes in meter operations for a subset of the projects but will be expanded as more projects complete smart meter deployments, integrate meter functions with utility information systems, and improve business processes. DOE-OE will work closely with the SGIG projects to elucidate how and to what extent AMI improves operational efficiency. Collaboration with the projects includes reviews of the results with the appropriate project teams so that they can be validated and lessons learned can be shared.

DOE-OE plans to present additional results and lessons learned in the future. In the meantime, updates on deployment progress and case studies highlighting project examples are posted regularly on www.smartgrid.gov.

Appendix A. SGIG AMI Projects

● The AMI feature/integration is enabled.

○ The AMI feature is under development.

Projects	Smart Meter Deployment as of 6/30/2012			Meter Features Enabled as of 6/30/2012					IT System Integrated as of 6/30/2012			
	Installed	Planned	% Installed	Remote Meter Reading	Outage Detection and Notification	Remote Service Switching	Tamper Detection	Voltage and Power Quality Monitoring	With Billing	With CIS	With DMS	With OMS
Baltimore Gas and Electric Company	22,623	1,272,911	0%	●	○	○	○	○	●	●	○	○
Black Hills/Colorado Electric Utility Company	44,920	44,920	100%	●	●	●	●	●	●	●	○	
Black Hills Power	68,980	68,800	100%	●	●	●	●	●	○	○	○	
Burbank Water and Power	52,163	52,257	100%	●	●	●	●	●	●	●	○	○
CenterPoint Energy	2,125,878	2,242,650	95%	●	●	●	●		●	●		●
Central Lincoln People's Utility District	20,595	38,283	54%	●	●	●	●	●	○		○	
Central Maine Power Company	613,130	630,000	97%	●	○	●	○	○	○	○	○	○
Cheyenne Light, Fuel and Power Company	39,102	39,102	100%	●	●	●	●	●	○	○	○	
City of Anaheim, California	7,795	20,000	39%	●	●	●			●	●		●
City of Fort Collins Utilities	0	84,290	0%	●	○	○	○	○	○	○	○	
City of Fulton, Missouri	0	5,762	0%	●	○	○	○	○	○			○
City of Glendale, California	84,096	86,526	97%	●	●	●	●	●	●	●	○	○
City of Leesburg, Florida	180	23,000	1%	●	●	●	●	●	●	●	○	○
City of Naperville, Illinois	37,889	57,323	66%	●	●	●	●	●	○			
City of Ruston, Louisiana	10,596	10,596	100%	●	●	●	●	●	●	●	○	○
City of Wadsworth, Ohio	12,557	12,750	98%	●	●	●	●	●	○			
Cleco Power LLC	16,426	279,000	6%	●	○	○	●	○	○			
Cobb Electric Membership Corporation	191,888	195,000	98%	●	●	●	●	●	●	●		
Connecticut Municipal Electric Energy Cooperative	19,371	22,395	86%	●	○	●	○	●	○	○	○	○
Denton Country Electric Cooperative (d/b/a/CoServ Electric)	19,938	168,192	12%	●	○	○	○	○	○			
Detroit Edison Company	625,468	625,468	100%	●	●	●	●	●	●	●	●	●
Duke Energy Business Services LLC	597,347	765,961	78%	●	○	●	●	○	●	●	●	●
Entergy New Orleans, Inc.	4,855	4,855	100%	●	○	○	○		●	●		
EPB	134,545	170,000	79%	●	●	○	○	●	○	○	○	
FirstEnergy Service Corporation	5,071	44,000	12%	●				○				
Florida Power & Light Company	2,359,736	3,000,000	79%	●	○	○	●	○	●	●	○	○

Projects	Smart Meter Deployment as of 6/30/2012			Meter Features Enabled as of 6/30/2012					IT System Integrated as of 6/30/2012			
	Installed	Planned	% Installed	Remote Meter Reading	Outage Detection and Notification	Remote Service Switching	Tamper Detection	Voltage and Power Quality Monitoring	With Billing	With CIS	With DMS	With OMS
Golden Spread Electric Cooperative, Inc. – Bailey Company	451	1,710	26%	●	●	○	○	●	○	○	○	
Golden Spread Electric Cooperative, Inc. – Big Company	9,818	10,749	91%	●	●	○	●	○	●	●		●
Golden Spread Electric Cooperative, Inc. – Deaf Smith	12,475	12,475	100%	●					●	●		
Golden Spread Electric Cooperative, Inc. – Lamb Company	10,400	10,400	100%	●	●	●	○	●	●	●	●	●
Golden Spread Electric Cooperative, Inc. – Lyntegar	18,162	18,162	100%	●	●	○	●	●				
Golden Spread Electric Cooperative, Inc. – North Plains	2,031	2,200	92%	●	○	○	○	○	○	○	○	
Golden Spread Electric Cooperative, Inc. – Rita Blanca	499	722	69%	●	●	●	●	○	●	●	○	
Golden Spread Electric Cooperative, Inc. – South Plains	9,391	12,495	75%	●	●	○	●	●	●	○		●
Golden Spread Electric Cooperative, Inc. – Taylor	12,426	12,426	100%	●	●	●	●	●	●	●	●	●
Guam Power Authority	0	56,735	0%	●	○	○	○	○	○	○	○	○
Idaho Power Company	380,928	475,000	80%	●	○	○	●	○	●	●		●
Indianapolis Power & Light Company	10,116	10,400	97%	●	○	○	●	○	○	●		○
Iowa Association of Municipal Utilities	1,716	5,450	31%	●	○	○	●	○	○	○	○	○
Jacksonville Electric Authority	23	3,000	1%	●	○	○			●	●		○
Knoxville Utilities Board	3,358	4,200	80%	●	●	●	●	○	○	●		○
Lafayette Consolidated Government, Louisiana	31,736	62,300	51%	●	○	○	●	○	●			
Lakeland Electric	101,012	124,000	81%	●	○	○	○	○	○			○
Madison Gas & Electric Company	4,355	4,500	97%	●	○					○	○	
Marblehead Municipal Light Department	6,720	10,800	62%	●	●	○	●	○	●	●		●
Minnesota Power	6,543	8,030	81%	●	●	●		●	●	●		
Modesto Irrigation District	3,320	3,348	99%	●	●	●	●	●	●	○	○	
Navajo Tribal Utility Authority	N/R	28,000	0%	●	●	●	●	●	○	●		
New Hampshire Electric Cooperative, Inc.	44,651	82,444	54%	●	●	○	●	●	○	○	○	○
NV Energy, Inc.	902,272	1,294,239	70%	●	●	●	●	●	●			
Oklahoma Gas & Electric	667,208	790,215	84%	●	●	●	●	●	●	●	○	○

Projects	Smart Meter Deployment as of 6/30/2012			Meter Features Enabled as of 6/30/2012					IT System Integrated as of 6/30/2012			
	Installed	Planned	% Installed	Remote Meter Reading	Outage Detection and Notification	Remote Service Switching	Tamper Detection	Voltage and Power Quality Monitoring	With Billing	With CIS	With DMS	With OMS
Pacific Northwest Generating Cooperative	85,325	97,666	87%	●	●	●	●	●	○			○
PECO	136,677	600,000	23%	●	○	○	●	○	○	●	○	○
Potomac Electric Power Company – District of Columbia	257,224	270,000	95%	●	●	●	●	●	○		○	
Potomac Electric Power Company – Maryland	156	550,000	0%	●	●	●	●	●	○	●	●	
Progress Energy Service Company	0	160,000	0%	●	○	○	○	○	○	○	○	
Rappahannock Electric Cooperative	50,708	52,600	96%	●	●	●	●	○	●	●		●
Sacramento Municipal Utility District	617,502	617,502	100%	●	●	●	○	●	●	●		
Salt River Project Agricultural Improvement and Power District	431,913	580,893	74%	●		●	●		○	○	○	
Sioux Valley Energy Southwestern Electric Cooperative Inc.	16,534	29,000	57%	●	●	●	●	●	●	●	●	●
South Kentucky Rural Electric Cooperative Corporation	66,407	68,000	98%	●	●	●	●	●	●	●		●
South Mississippi Electric Power Association – Coast	78,867	78,867	100%	●	●	●	●	●	○			
South Mississippi Electric Power Association – Magnolia	9,379	30,000	31%	●	●	○	●	○	○		○	
South Mississippi Electric Power Association – Pearl River Valley	25,161	31,861	79%	●	●	●	●	●	●		●	
South Mississippi Electric Power Association – Southern Pine	56,326	57,162	99%	●	●	●	○	○	●			
South Mississippi Electric Power Association – SW Mississippi	18,977	25,000	76%	●	○	○	○		●		○	○
Southwest Transmission Cooperative, Inc. – Mojave	31,701	31,701	100%	●	○	●	●	●				
Stanton County Public Power District	2,299	2,315	99%	●	●	○	○	●				
Talquin Electric Cooperative	50,813	56,000	91%	●	●	●	●	●	○	○	●	●
Town of Danvers, Massachusetts	4,058	12,839	32%	●	●	●	●	●	●	●	○	○
Tri-State Electric Membership Corporation	15,156	15,156	100%	●	●	●	●	●	●			
Vermont Transco, LLC	84,828	311,380	27%	●	●	○	●	●	●	●		●
Wellsboro Electric Company	2,085	4,589	45%	●	●	○	●	●	○			●
Westar Energy, Inc.	42,597	45,000	95%	●	●	●	●	○	●			
Woodruff Electric Cooperative	13,966	14,450	97%	●	●	●	●	●	●	●		