

# Chapter 6: Enhancing the Distribution System

In this chapter, we focus on the potential for new technologies to enhance the performance of distribution systems. New sensors, communication equipment, management systems, and automation and information technologies promise to improve the efficiency, reliability, and power quality of distribution systems.

Section 6.1 introduces technologies that promise to enhance distribution system operation. We describe the potential of more fully integrated distribution management systems, then introduce several new distribution system operation applications. These include automated fault detection, isolation, and restoration systems as well as voltage and power flow optimization systems. We find that many individual technologies that could enhance the distribution system are complementary, and the benefits from their deployment will be greatest when utilities use an integrated approach to system modernization.

Section 6.2 contains a more in-depth discussion of one particular distribution system technology: advanced metering infrastructure (AMI). We describe several categories of operational benefits of AMI and analyze the costs and benefits of AMI based on recent utility regulatory filings. We highlight the importance of the nonoperational benefits associated with AMI, to be discussed in more detail in Chapter 7.

Section 6.3 discusses the importance of learning from technology pilot programs and early deployments. The costs and benefits of new distribution technologies are subject to significant uncertainty. Detailed information generated from pilots and early deployments will enable utilities and their regulators to make more informed decisions on both investment priorities and system design.

Finally, Section 6.4 describes our conclusions and details this chapter's one recommendation. Recognizing the importance of data from distribution technology pilot programs and early deployments, we recommend that policy makers work to ensure that comprehensive data from Recovery Act–funded programs are shared as widely as possible throughout the industry.

The distribution system is the portion of the electric power system that carries power the few miles remaining between transmission substations and consumers. In addition to transporting electricity, the distribution system

- transforms voltage to the appropriate level for customer use;
- regulates voltages within a limited range;<sup>1</sup>

- detects faults and other abnormal situations on the distribution system and takes action to protect people and system components; and
- restores service following interruptions.

Today, less than 7% of total electrical energy in the U.S. is lost between generators and customers, and most of this loss occurs in the distribution system.<sup>2</sup> Reliability for individual customers varies widely, but averages in

different regions of the U.S. tell us that customers can expect between 1.5 and 2 power interruptions per year and between 2 and 8 hours without power.<sup>3</sup> According to the relevant literature, 80% of interruptions are due to problems in the distribution system.<sup>4</sup> The

### *80% of interruptions are due to problems in the distribution system.*

percentage of customer outage time attributable to the distribution system can be much higher in some specific cases; for example, the distribution system was responsible for at least 95% of interruptions<sup>i</sup> in the Southern California Edison service region from 2006–2009 and 92.6% of Florida Power & Light interruptions in 2009.<sup>5</sup>

Power quality refers to the degree to which voltage levels are accurate and constant, and the voltage waveform is a pure sinusoid. Power quality can be compromised by certain types of electrical loads as well as distribution system equipment. Distributed generators may contribute as well, as discussed in Chapter 5. Power quality issues generally do not cause problems with customer equipment because modern power supplies for phones, computers, televisions, and other electronics can accept a very large variation in voltage level and shape.

Providing efficiency, reliability, and power quality is expensive for utilities and ratepayers, but inefficiency and poor reliability also have costs. Up to a certain point, investments in system hardware represent a net gain to society. Beyond that level, additional improvements from investments may not be cost effective. The optimal level of service varies greatly depending on individual customer needs. An underlying

principle in any discussion of new distribution investment should be that there is a trade-off between cost and level of service.

Measuring service quality is an important input to this assessment, but little attention has been paid to measurement, collection, and publication of standardized performance metrics across U.S. distribution utilities. Previous attempts to compile such data have highlighted differences in definitions and data collection processes.<sup>6</sup> More fundamentally, as of 2008, only 35 state public utility commissions (including the District of Columbia) required reporting of standard distribution performance metrics, though this represented an increase over a previous count in 2004.<sup>7</sup> Whereas European regulators have made a coordinated effort to regularly compile comprehensive data from distribution utilities across Europe and account for definitional and geographical differences,<sup>8</sup> no effort on that scale has taken place in the U.S. Improving these data could facilitate evaluation of investment opportunities going forward, as we recommend in Chapter 8.

## **6.1 OPPORTUNITIES IN DISTRIBUTION SYSTEM OPERATION**

The integration of new communications infrastructures, sensor technologies, and advanced information technology will enable new distribution system capabilities over the next several decades. While many of these technologies have existed for some time, their deployment in U.S. distribution systems has been limited.

Utilities historically have employed a variety of manual or semi-automated systems to monitor system status, manage work crews,

<sup>i</sup> Percent of interruptions are calculated using SAIDI (system average interruption duration index) values. SAIDI, a reliability indicator commonly used by electric utilities, is the average outage duration for each customer served, usually measured in minutes per year. See the glossary for details.

detect outages, manage assets, manage infrastructure upgrades, and perform other tasks. Historically, a distribution system failure would be discovered when customers called the utility to complain about lack of power. Then the utility would send out a crew to track down and repair the problem. Some utility companies developed ad-hoc management systems to track and assign line crews. Lack of real-time instrumentation throughout distribution networks often limited the effectiveness of these tools, and standardization was largely nonexistent.

Distribution systems today are a product of this history. In many areas, today's distribution companies still employ essentially the same process for locating and managing outages as decades ago. In other areas, systems have evolved—but not always in the same direction, resulting in heterogeneous distribution systems around the country. This heterogeneity reflects the general lack of standardization as well as differences in geography and regulatory practices across state boundaries.

Recent advances in information and communication technologies have enabled the development of significantly more sophisticated distribution management systems (DMS) that can handle and fully integrate a wide variety of system management tasks. Beyond providing real-time visibility into the state of assets throughout the distribution system, state-of-the-art DMSs often can simulate distribution system power flows in near-real time, helping operators anticipate or respond to potential problems. For example, these systems can allow operators to determine whether changing the configuration of the distribution network in response to faults will result in a system with appropriate voltage levels and current flows. In conjunction with other technologies, modern DMSs promise to make distribution system operators more agile and responsive to real-time system conditions.

DMSs in use today run the gamut from modern to outdated. Surprisingly, some distribution utilities still use paper maps to keep records, track problems, and manage work crews. In contrast, electronic maps allow for easy updating, quick searches through large geographic areas, and clear communication

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with work crews. Electronic maps are only one example of the changes that upgrades in distribution software can bring. However, in an industry that prizes reliability and depends on tested operating procedures to maintain reliability, such fundamental changes come at the cost of extensive training programs and a period of heightened risk as personnel become accustomed to new practices.

The time, money, and expertise required to implement a new DMS can vary greatly between utilities because a significant level of customization is necessary. A variety of equipment throughout the distribution system can be enabled to interact with DMSs. Many new sensors, protection equipment, and control devices have communication and computation capabilities. The number of sensors that a utility deploys and integrates with its DMS impacts the cost and time required for implementation and the usefulness of the resulting DMS. To upgrade its DMS from a software system developed in-house to a state-of-the-art vendor solution, one California utility attributed 40% of the estimated implementation cost to labor, IT, and equipment upgrades and 60% of the cost to software vendor services.<sup>9</sup>

Outage management systems (OMS) are another tool in the software suites that distribution system operators use. Sometimes viewed as a component of DMSs, OMSs typically use system models and graphical user interfaces to handle customer complaint calls, locate outages, and manage repair crews.<sup>10</sup> State-of-the-art OMSs can incorporate geographic information systems, electrical models, and real-time data from sensors to provide sophisticated, real-time visualization of the system during outages. Improved work-management software and real-time outage information with clearer communication between mobile units and control centers can increase the speed with which crews reach faults and the safety of their actions. A recent Lawrence Berkeley National Laboratory study quantifies the economic benefit of reducing outage time: using data from customer surveys, its authors conclude that the cost of an outage lasting one hour is approximately \$4 for residential customers, \$800 for small commercial and industrial customers, and \$20,000 for medium and large commercial and industrial customers.<sup>11</sup> Of course, the actual costs of outages vary widely across different customers and regions, and computing average values requires a range of assumptions regarding outage and customer characteristics.

Integrating communications, IT infrastructure, and sensors with DMSs will enable a range of new distribution system operation applications. Two prominent examples are automated fault detection, isolation, and restoration (FDIR, also known as self-healing) and optimization of system voltages and power flows. The term “distribution automation” is often used to generically describe these applications of new technology to the maintenance, control, and operation of the distribution network. We address these new applications in the rest of this section.

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## FINDING

**The use of new communication, sensor, and advanced information technologies can result in the integration and automation of many distribution system functions, yielding reduced costs and improved reliability.**

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### **Automated Fault Detection, Isolation, and Restoration**

More extensive deployment of circuit breakers and communication devices combined with advanced control algorithms can enable automatic FDIR. As an example of FDIR in action, consider an automobile accident that knocks down a pole supporting distribution wires, interrupting service to customers. A distribution system with software for automatic FDIR in place that also includes multiple feeders and sectionalizing switches—switches that divide lines into independent sections—can isolate the site of the fault (the downed wires), perform analysis to determine the extent of damage and options for reconfiguration, and provide a secondary path for service to customers who would otherwise be without power.

This self-healing capability has the potential to improve reliability, enhance customer service, and reduce operation and management costs.<sup>12</sup> Deploying automated FDIR in legacy systems can speed these processes by removing the need for human action and decision-making. In distribution systems that already use automated FDIR processes, the addition of advanced control algorithms and more finely sectionalized distribution circuits in these systems can reduce the time of outages and the number of customers affected. For example, Oklahoma Gas & Electric Company reduced its outage time by between 54% and 70% on three circuits after installing hardware enabling FDIR capability.<sup>13</sup>

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To date, self-healing technology has been installed on only a small percentage of distribution feeders in the U.S.<sup>14</sup> Typically, the least reliable circuits in distribution systems are first to be upgraded because improving them will be of the most benefit to customers and the cost of deployment discourages system-wide upgrades. Many distribution utilities are now demonstrating this technology through projects partially funded by American Recovery and Reinvestment Act grants.<sup>ii</sup>

### Voltage and Power Flow Optimization

As customers draw power from the distribution system, voltages decline along distribution lines. Without intervention, the voltage level at the end of a long distribution line will be lower than at the substation. With some exceptions, the size of the voltage drop increases when loads increase. To control voltage at the customer load point, utilities have long used adjustable transformers, known as “voltage regulators,” and “capacitor banks”—a collection of capacitors that can be switched in and out of the circuit—to keep voltages within a specified range along the entire length of distribution lines. These devices are controlled from the distribution substation, which ensures that the voltage for each customer is between 95% and 105% of rated voltage.<sup>15</sup> For residential customers, where the rated voltage is 120 volts, this gives an acceptable range of 114–126 volts.

Manufacturers design equipment, such as motors, to operate optimally within the range of  $\pm 5\%$  of nominal voltage. Supply voltage outside the acceptable range can result in inefficient operation and overheating, leading to reduced equipment life.

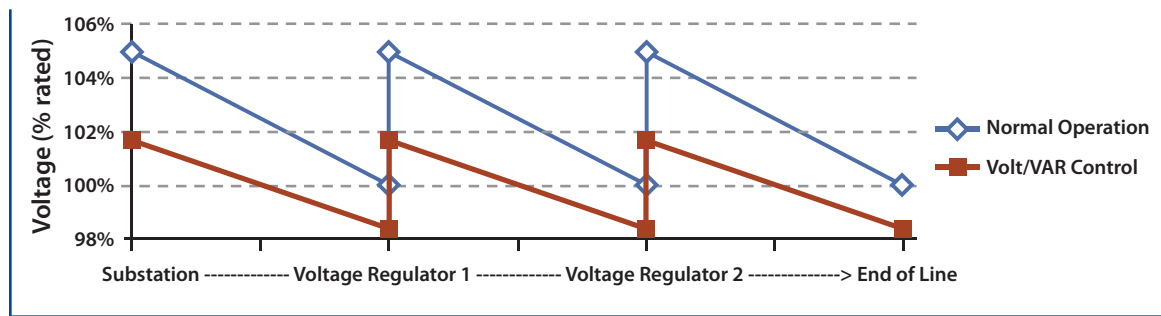
Operating at the upper end of the allowable voltage range is a common strategy because voltage is measured at the substation but not at the end of the line; to ensure the voltage at the end of the line is within limits, utilities often set the substation voltage at the upper end of the specification. Because load will draw more power with a higher voltage, tighter control of voltage can result in reduced power consumption.<sup>iii</sup> Tighter voltage limits and its benefits can be effected by a more sophisticated approach to voltage regulation called “volt/VAR control” which employs voltage sensors on the line, and particularly at its end, which feed back the measured voltages to the substation. Control equipment at the substation then adjusts the substation voltage and the voltage regulating equipment on the line to maintain the line voltage at the low end of its limits.

Figure 6.1 illustrates the potential effect of volt/VAR control on the voltage along a distribution feeder. In the figure, the vertical axis is voltage level and the horizontal axis, from left to right, represents the distance of a distribution line from the substation to the end of the line. The blue lines show the voltage distribution under normal operation, where voltage measurements are not fed back to the substation. The voltage variation along the line is seen to be 5%. The red lines represent the voltage distribution using volt/VAR control. The effect of sensing and feedback control is not only to

<sup>ii</sup> Track these projects at <http://www.smartgrid.gov>.

<sup>iii</sup> This relationship depends on the nature of the load. The correlation is very strong for resistive loads, such as incandescent lamps, but weak for many electronic devices with modern power supplies that compensate for voltage variations.

**Figure 6.1 Voltage Profiles with and without Volt/Volt-Ampere Reactive (VAR) Control**



reduce the average value of the voltage while maintaining it within its acceptable limits, but also to tighten its variation along the line to less than 4%.

Volt/VAR control also can be applied to reduce peak loads by decreasing feeder voltage to the lower end of the acceptable range. This approach, known as conservation voltage reduction (CVR), can yield a decrease in the total power drawn throughout the network, thereby deferring the need for capacity expansion and increasing efficiency. In a three-year study conducted for 13 utilities (30,000 customers) in the Pacific Northwest, maintaining the voltage between 114 and 120 volts at the customer level every other day yielded a 2% savings in annual energy delivered by substations.<sup>16</sup> Unlike brownouts or rolling blackouts, conservation voltage reduction does not necessarily negatively impact the quality of service that utilities provide to their customers.

Many utilities are currently planning to introduce volt/VAR control and CVR programs in their territory. Oklahoma Gas & Electric Company calculated that installing volt/VAR control on 400 of their highest-priority circuits would save 106 gigawatt hours per year, or approximately 0.4% of their annual energy sales, and defer 80 megawatts of future generation on their existing capacity of 6,800 megawatts.<sup>17</sup> Southern California Edison is deploying a CVR program that uses voltage data from

their advanced metering infrastructure and is estimated to save their customers between 1% and 4% of energy consumption without any behavior changes.<sup>18</sup>

#### FINDING

**The use of Volt/VAR control can result in more efficient use of the distribution network and the possibility of introducing conservation voltage reduction (CVR) programs.**

As discussed in Chapter 8, the practice of utilities recovering a substantial portion of their distribution and transmission costs through volumetric charges, as is currently the dominant practice in the U.S., gives utilities incentives to increase their sales and discourage energy conservation. This incentive misalignment could slow the introduction of CVR programs that promise reduced energy consumption.

## 6.2 ADVANCED METERING FOR THE DISTRIBUTION SYSTEM

New customer-metering investments also can enhance the performance of distribution systems. Utilities traditionally have used meters strictly for billing purposes. In this traditional paradigm, utility employees visit customer premises and manually read electromechanical

watt-hour meters that measure electric energy consumption. These meters are no longer commercially available in the U.S., having been replaced by solid-state electronic meters, though many electromechanical meters are still in use today.<sup>19</sup> Electronic meters can more easily store and communicate energy consumption as a function of time. These new meters have enabled two distinct new approaches to data capture and management: automated meter reading (AMR) systems and advanced metering infrastructure (AMI) systems.<sup>20</sup>

AMR technology allows utilities to read customer meters via short-range radio-frequency signals. These systems typically capture meter readings from the street using specially equipped vehicles. They can reduce meter-reading costs by eliminating the need for employees to manually read meters. Many utilities throughout the U.S. have deployed AMR systems over recent decades, with more than 47 million AMR meters reported in operation as of 2009, roughly one-third of the 144 million total U.S. residential, commercial, and industrial meters.<sup>21</sup>

AMI systems—also known as smart meters—combine meters with two-way communication capabilities. These systems typically are capable of recording near-real-time data on power consumption and reporting that consumption to the utility at frequencies of an hour or less.<sup>22</sup> Utilities also can typically communicate with AMI meters—for example, to check customer connection status or connect or disconnect service remotely. AMI systems also can allow utilities to communicate directly with loads through the meter, as discussed in Chapter 7. In contrast to AMR systems, AMI installations in the U.S. are still in their infancy but are growing rapidly. Penetration estimates vary across the industry. In 2009, data submitted by the industry to the U.S. Energy Information Administration indicated that 9.6 million customer meters in the U.S. were AMI devices.<sup>23</sup> The Federal Energy Regulatory Commission’s 2010

advanced metering survey reported penetration of more than 12 million smart meters by the end of 2009.<sup>24</sup> The difference likely reflects not just growth but also differences in data sources. The federal government has subsidized additional deployment of AMI systems in a number of utilities through the Recovery Act, supporting approximately 30 large deployments throughout the U.S.<sup>25</sup> An estimated 20 million AMI meters have been deployed nationwide as of June 2011.<sup>26</sup>

The benefits of advanced metering vary with every utility, but generally it reduces the costs of meter reading, improves customer support, and enhances distribution monitoring and management. For example, AMI meters equipped with remote service switches allow utilities to remotely connect or disconnect service when customers move in or out. This can reduce the time and cost of connections, eliminate usage that occurs after customers have closed their accounts, and may reduce uncollected bills. Some utility AMI rate filings indicate that enhanced detection of theft or diversion—that is, electricity use that bypasses a meter—may increase revenues. Of great import, however, is the role AMI, and particularly its two-way communication capability, can play in facilitating dynamic pricing for residential customers, as discussed in Chapter 7.

In regulatory filings, utilities mainly have focused on quantifying the following operational benefits of AMI:

- **Metering:** Installation of AMI means that meter reading can be fully automated. This reduces labor cost and the costs of owning and maintaining meter-reading vehicles.

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- **Billing:** Billing can be more accurate and timely, improving utilities' cash flows.
- **Customer Support:** Service can be switched on or off remotely, increasing accounting accuracy, reducing customer debts, and reducing the number of times utility personnel must visit customer locations. In addition, call centers can more effectively help customers because of readily available and accurate metering data, thereby reducing the average duration of customer support calls.
- **Grid Management:** The data from interval metering (meters that can be read at intervals of an hour or less) can be used to more effectively manage distribution system assets; for example, precise metering can alert distribution operators to an overloaded distribution transformer.

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While the operational benefits of installing AMI can be substantial, they may not cover the full cost of the up-front infrastructure investment. Table 6.1 presents expected costs and benefits for a sample of AMI projects around the country, collected by a search of regulatory filings. The expected all-in costs of AMI deployments over the past five years averaged between \$150 and \$400 per meter across these projects, with much of the variation due to differences across systems in customer mix and density, labor costs, and prior meter investments. Recent discussions of AMI costs and benefits frequently use a lower range of expected costs, \$150–\$250 per meter, though it is not clear how these estimates relate to data on actual deployments.<sup>27</sup> For systems with dispersed customers, traditional electro-mechanical meters near the end of their expected useful lives, and combined electricity

and gas businesses that can share much of the AMI infrastructure and overhead, operational savings may cover a high fraction of AMI deployment costs. Where operational benefits roughly offset the investment costs, there may be little or no impact on electricity rates, and a decision to deploy AMI is relatively straightforward. At the other extreme, utilities with relatively new AMR meters throughout their system have already realized much of the meter-reading cost reductions, the largest single category of operational benefits of AMI, and may be adding little to the useful lives of their meter system through early replacement. For systems in this situation, operational savings may offset half or less of the projected incremental cost of AMI deployment. In the most extreme case illustrated in Table 6.1, operational savings cover only 15% of AMI costs.

In some cases, these benefit–cost ratios may be conservative. AMI investments that can be funded entirely out of operational savings may not generate a rate filing and, therefore, do not appear in our table. In rate filings, concerns have been expressed that utilities fear overestimating savings that do not later materialize or incurring costs above those approved in initial rate filings, particularly if the regulator assigns most of the risk to shareholders, as some have recently done. These concerns may bias reported benefit–cost ratios below expected levels.

Operational savings are also not the only benefit of AMI. Advocates of AMI argue that the nonoperational benefits from AMI-enabled demand response and energy conservation dwarf the operational savings.<sup>28</sup> Their importance to an AMI investment case depends on what fraction of costs are offset by operational savings, whether utilities and regulators are willing to commit to pricing reforms, and how customers within a particular service area are likely to respond. Table 6.1 includes several estimates of these

**Table 6.1 Operational Benefit–Cost Ratio of Different Advanced Metering Projects**

Utility (State)	Year	Meters (Millions)	Average Cost/Meter Installed (\$/meter)	Operational Benefits/Meter Installed (\$/meter)	Operational Benefits/Cost Ratio	Nonoperational Benefits/Meter Installed (\$/meter)	Total Benefits/Cost Ratio	Reference
CenterPoint (TX)	2008	2.4	\$332	\$50	0.15	—	—	CenterPoint Energy Houston Electric, “Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System,” Texas PUC Docket No. 35639, Document No. 203.
Delmarva (MD)	2010	0.22	\$363	\$183	0.50	\$252	1.20	Delmarva Power & Light Company, “Advanced Metering Infrastructure Business Case and Associated Benefits to Costs Analysis for Maryland in Compliance with Order No. 83571,” Maryland Public Service Commission Case No. 9207, Document No. 102, submitted 12/14/2010.
Southern California Edison (CA)	2007	5.3	\$374	\$217	0.58	\$159	1.00	California Public Utility Commission, “Decision Approving Settlement on Southern California Edison Company Advanced Metering Infrastructure Deployment,” Case No. A.07-07-026, 7/31/2007.
Connecticut Light & Power (CT)	2010	1.2	\$377–\$484	\$94–\$232	0.19–0.62	\$63–\$804	0.33–2.75	Connecticut Light & Power, “CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis,” Connecticut Department of Public Utility Control, Docket No. 05-10-03RE01, submitted 3/31/2010.
Portland General Electric (OR)	2007	0.843	\$157	\$197	1.26	\$4–\$55	1.28–1.61	B. Carpenter and A. Tooman, Portland Generation Electric Company, “Costs and Benefits,” Oregon Public Utility Commission, Docket No. UE 189, submitted 7/27/2007.
Baltimore Gas & Electric (MD)*	2009	2.09	\$253	\$128	0.50	\$478	2.40	Baltimore Gas & Electric Company, “The Smart Grid Initiative Business Case Advanced Metering and Smart Energy Pricing Program” Maryland Public Service Commission, Case No. 9208, submitted 07/13/2009.
NY State Electric & Gas (NY)*	2007	1.13	\$322	\$185	0.58	—	—	Rochester Gas & Electric Corporation and New York State Electric & Gas Company, “Advanced Metering Infrastructure Overview and Plan,” New York State Public Service Commission Case No. 00-E-0165, submitted 02/1/2007.

**Table 6.1 Operational Benefit–Cost Ratio of Different Advanced Metering Projects** *continued*

Utility (State)	Year	Meters (Millions)	Average Cost/Meter Installed (\$/meter)	Operational Benefits/Meter Installed (\$/meter)	Operational Benefits/Cost Ratio	Nonoperational Benefits/Meter Installed (\$/meter)	Total Benefits/Cost Ratio	Reference
Rochester Gas & Electric (NY)*	2007	0.67	\$250	\$150	0.60	—	—	Rochester Gas & Electric Corporation and New York State Electric & Gas Company, “Advanced Metering Infrastructure Overview and Plan,” New York State Public Service Commission Case No. 00-E-0165, submitted 02/1/2007.
Consolidated Edison (NY)*	2007	4.8	\$149	\$109	0.73	\$55	1.10	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., “Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure by Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.,” New York State Public Service Commission Case No. 00-E-0165, submitted 3/28/2007.
Pacific Gas & Electric (CA)*	2006	9.3	\$243	\$218	0.90	\$36	1.05	California Public Utility Commission, “Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure,” Decision 06-07-027, July 20, 2006.

\*These projects include upgrades to natural gas metering systems in addition to electricity metering upgrades. The number of meters for these projects corresponds to both electricity and gas meters.

Note: The data in Table 6.1 has been extracted from state regulatory proceedings. Prospective calculations of AMI benefits and costs require a range of assumptions (e.g., project lifetimes, depreciation schedules). Also, as described in the text, these results are subject to significant uncertainty (e.g., technology costs, deployment schedules, dynamic pricing adoption rates, etc.). The cost of AMI projects also depend on the characteristics of each utility’s service territory and the nature of their existing technology and business processes related to customer metering.

nonoperational benefits of AMI investments. Unfortunately, these are much more difficult to estimate with precision. Chapter 7 addresses these issues in detail.

Most utility regulatory filings also omit reliability gains from benefit–cost calculations. AMI can allow some utilities to respond more rapidly to distribution outages and reduce average outage restoration times for customers. Although the frequency or scale of distribution outages cannot be lowered by using advanced metering systems alone, AMI can enable utilities to quickly and automatically pinpoint where an outage has occurred and respond more rapidly with service vehicles, reducing the average outage time experienced by customers.

In addition, identifying “false alarms”—outage reports called in when electricity is in fact flowing to the meter—may reduce costs by avoiding unnecessary dispatch of crews, although malicious hacking of AMI data could create such alarms (see Chapter 9 for further discussion of so-called “cyberattacks”).

In the one filing that does incorporate this benefit, Connecticut Light & Power estimates a reduction in average yearly outage duration of six minutes per customer, mainly attributed to “increased notification accuracy that AMI provides during storms.” In a base-case scenario, the utility estimates that the expected reduction in outage minutes alone would account for \$59 million in benefits over the

lifetime of a \$493 million AMI investment program, using reasonable estimates of outage costs from a survey of outage-cost studies.<sup>29</sup>

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## FINDING

**The ratio of operational benefits to total cost for AMI projects varies widely across different utilities. Where operational benefits are low, nonoperational benefits, such as those associated with demand response programs, are a significant factor in determining whether AMI installations are cost-effective.**

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For systems that have begun deploying AMI, customers' concerns about health and privacy impacts can pose important challenges. Early and effective engagement with customers appears critical to surmounting these concerns.

While the scientific literature does not suggest that radio waves from smart meters have adverse health effects, debate over these risks can be so intense that utilities must retool AMI programs in response.<sup>30</sup> Citing customer concerns, the Maine Public Utility Commission recently approved a meter surcharge program that would allow customers to opt out of smart meter installation or turn off the wireless transmitting function, and Pacific Gas & Electric has proposed a similar program for its territory.<sup>31</sup>

Privacy issues surrounding AMI arise from the fact that smart meters measure and record customer's power usage at frequent intervals. The power usage profiles thus accumulated could be used to infer, for example, when a customer is away on vacation. The National Institute of Standards and Technology and several state public utility commissions are actively addressing these privacy concerns, which have gained international attention. We discuss the intricacies of this issue in Chapter 9.

## 6.3 PILOT PROGRAMS AND DEPLOYMENT CHALLENGES

The Recovery Act provided about \$4.5 billion for the electric grid, and many utilities have used this funding for advanced distribution system technology projects. The bulk of this funding is being distributed through two U.S. Department of Energy programs: Smart Grid Demonstration Projects (SGDP) and Smart Grid Investment Grants (SGIG). The goal of SGDP is "to demonstrate new and more cost-effective smart grid technologies, tools, techniques, and system configurations that significantly improve on the ones commonly used today." The SGIG program aims "to accelerate the modernization of the nation's electric transmission and distribution systems and promote investments in smart grid technologies, tools, and techniques that increase flexibility, functionality, interoperability, cybersecurity, situational awareness, and operational efficiency."<sup>32</sup> Each funding opportunity required recipients to provide one-to-one matching funds. Ninety-nine SGIG recipients have been awarded a total of \$3.4 billion and 32 SGDP recipients have been awarded a total of about \$600 million.

Many award recipients are using the funding to accelerate distribution modernization efforts. For example, NSTAR has been installing hardware required to sectionalize circuits since 2003; prior to the SGIG award in 2009, 1,200 sectionalizing switches already had been installed. Using SGIG funding, NSTAR will upgrade from an FDIR system requiring human action to one that is completely automated; roughly 70% of circuits will have self-healing (automated FDIR) capabilities by the end of 2013, and the utility expects that 50% fewer customers will experience outages as a result.<sup>33</sup> Similarly, PPL Electric Utilities has been installing hardware allowing remote control of their distribution system since 2003 and is now using SGIG funding to install DMS

software, a dedicated communication system, and new hardware enabling full automation of about 50 circuits. With modern DMS software and a communications network in place, further hardware upgrades enabling full automation of other PPL circuits are expected in future investments.<sup>34</sup>

The projects funded by SGIG and SGDP programs may prove a beneficial step toward distribution system modernization. However, the value of these and future advanced distribution technology deployments and pilot projects will depend on effective information sharing, the development of interoperability standards, and efforts to properly align regulatory incentives with system modernization goals.

Currently, detailed information on federally funded smart grid projects, expected benefits, utility characteristics, progress, and lessons learned is sparse and insufficient to apply to other similar projects. Although industry can share information at several newly launched websites—including [www.sgiclearinghouse.org](http://www.sgiclearinghouse.org), [www.smartgrid.gov](http://www.smartgrid.gov), and [www.recovery.gov](http://www.recovery.gov)—very little of this information pertains to ongoing distribution modernization efforts. Getting detailed information has been difficult, despite efforts to individually contact funding recipients and collect detailed information on expected costs and benefits for a majority of proposed projects.

The White House Office of Science and Technology Policy has drafted a framework for the future grid that emphasizes the importance of information sharing.<sup>35</sup> A mechanism for sharing the results of publicly funded research, development, and demonstration projects is essential to ensure that the funding provided to one utility will benefit other utilities as well. Transparency to the public is important not only to ensure accountability but also to facilitate further research that may help guide future investments. However, utilities may be

appropriately unwilling to publicly share certain information due to concerns about security and the sensitive nature of some business information. Therefore, distribution utilities with common interests in advanced technologies may need to use direct channels for cooperation and communication. Indeed, industry stakeholders with whom we have spoken in the course of our research have indicated that a mix of informal and formal mechanisms for inter-utility collaboration exist in the U.S. today. Sometimes these activities are coordinated via such institutions as the Electric Power Research Institute and industry trade associations including the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association.

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## FINDING

### **Information sharing among Smart Grid Investment Grant and Smart Grid Demonstration Project funding recipients and other utilities is essential to capture the value of these projects.**

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Interoperability of IT equipment, software, and communications technologies from various vendors remains an important challenge. The National Institute of Standards and Technology has undertaken work to coordinate standards for the future grid that will address these interoperability issues. We address these standards and other interoperability concerns in Chapter 9.

We noted in Chapter 1 a general decrease in budgets for utility research and development activities, which may hamper innovative activity. Further, deploying new technologies frequently involves uncertainty about the economics and performance of those innovations. Conventional rate of return regulation with *ex post* prudence reviews of capital investments may discourage or delay

investments that are perceived to involve greater risks.<sup>36</sup> Regulators in many states may have cause to be similarly risk-averse toward significant new investments. This problem is addressed in greater depth in Chapter 8.

## 6.4 CONCLUSIONS AND RECOMMENDATION

Substantial changes to distribution system operation will occur between now and 2030. In large part, the changes discussed in this chapter are a necessary response to the new challenges that electric vehicles and distributed generation pose. Modern distribution management systems and other control center software are necessary to unlock the benefits from increased deployments of sensors and control hardware. Automated FDIR and volt/VAR control are technologies that require modern hardware and software but offer significant benefits in return. To the extent that these technologies facilitate aspects of performance that have not been the focus of traditional distribution system investments and involve greater uncertainty in their payoff, utility regulators and supervisors may need new approaches to encourage innovation. We discuss this at greater length in Chapter 8.

AMI systems offer clear operational savings, and many utilities already have committed to or executed broad deployment of this technology. For those that have not, particularly those with existing AMR systems, operational benefits alone may not be sufficient to justify the cost of a broad AMI rollout. Quantifying the likely magnitude of benefits from AMI-enabled demand response, energy efficiency programs, and increased reliability will be critical to assessing the business case for AMI investments for these utilities. We address these in detail in Chapter 7. We describe the privacy and cybersecurity concerns associated with this technology in Chapter 9.

Technology demonstrations and pilot projects are an important step toward implementing cost-effective advanced distribution technologies. Federal stimulus funding is currently supporting many such projects. Comprehensive inter-utility information sharing will be crucial to realizing the full potential of these public investments. Regulators only recently have introduced websites intended to facilitate information sharing about these projects, and the sites currently have little useful data related to ongoing projects. As these projects progress, these websites may yet facilitate industry learning. However, direct utility-to-utility communications and collaboration should also be encouraged to ensure that sufficiently detailed lessons learned from demonstration projects are available to inform future investment decisions. It is critical that utilities share details on both successes and failures.

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### RECOMMENDATION

**Achieving the full potential of federal funding for distribution system technology demonstration projects will require that data on those projects (both successes and failures) are shared widely. Several websites, including [www.smartgrid.gov](http://www.smartgrid.gov) and [www.sgiclearinghouse.org](http://www.sgiclearinghouse.org), have been established to disseminate information about these projects. As results become available, policy makers should work to ensure that resources such as these are effectively used to share detailed and comprehensive data and lessons learned.**

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To assure continuation of the modernization process initiated by the Recovery Act grants, state regulators and other supervisors of distribution utilities must be willing to approve investments that have a greater degree of risk than has been customary for distribution systems, as we discuss at length in Chapter 8.

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