PNNL-23461

Pacific Northwest NATIONAL LABORATORY
Proudly Operated by Battelle Since 1965

# Smart Grid Status and Metrics Report Appendices

**July 2014**

PJ Balducci
CA Antonopoulos
SL Clements
WJ Gorrissen
H Kirkham
KA Ruiz
DL Smith
MR Weimar
C Gardner, APQC
J Varney, APQC

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
*operated by*
BATTELLE
*for the*
UNITED STATES DEPARTMENT OF ENERGY
*under Contract DE-AC05-76RL01830*

**Printed in the United States of America**

**Available to DOE and DOE contractors from the**
**Office of Scientific and Technical Information,**
**P.O. Box 62, Oak Ridge, TN 37831-0062;**
**ph: (865) 576-8401**
**fax: (865) 576-5728**
**email: reports@adonis.osti.gov**

**Available to the public from the National Technical Information Service,**
**U.S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161**
**ph: (800) 553-6847**
**fax: (703) 605-6900**
**email: orders@ntis.fedworld.gov**
**online ordering: http://www.ntis.gov/ordering.htm**

This document was printed on recycled paper.
(9/2003)

# Smart Grid Status and Metrics Report Appendices


PJ Balducci
CA Antonopoulos
SL Clements
WJ Gorrissen
H Kirkham
KA Ruiz
DL Smith
MR Weimar
C Gardner, APQC
J Varney, APQC



July 2014

Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory
Richland, Washington 99352

# Table of Contents

# Figures

## Tables

# Appendix A

# Metrics Reports for the Smart Grid Status and Metrics Report

# Appendix A
# Metrics for the Smart Grid Status and Metrics Report

## Introduction

This appendix presents papers covering each of the 21 metrics identified in Section 2.1 of the Smart Grid Status and Metrics Report. These metric papers were prepared in advance of the main body of the report and collectively form its informational backbone. The list of metrics is derived from the material developed at the 2008 Smart Grid Implementation Workshop and refined through the development of this report. The objective of the metric development process was to distill the best ideas into a small number of metrics with a reasonable chance of successful measurement and assessment.

The metrics examined in this appendix are of two types: build metrics that describe attributes that are built in support of the smart grid, and value metrics that describe the value that may be derived from achieving a smart grid. Build metrics generally lead the value that is eventually provided, while value metrics generally lag in reflecting the contributions that accrue from implementations. While build metrics tend to be quantifiable, value metrics can be influenced by many developments and therefore generally require more qualifying discussion. Both types are important in describing the status of smart grid implementation.

Each metric paper is divided into five sections as outlined below:

- Introduction and Background: A brief introduction to the concepts addressed by the metric, including an overview of relevant issues.
- Description of Metric and Measurable Elements: An identification and description of the metric being evaluated.
- Deployment Trends and Projections: The current status of the metric, analysis of trends and projections, identification of relevant stakeholders and their relationship to the smart grid, and assessment of regional influences on smart grid deployment.
- Challenges to Deployment: An overview of the technical, business, and financial challenges to smart grid deployment.
- Metric Recommendations: Recommendations to improve metric measurement.

The content in these metric papers is summarized in sections of the main body of the report. References embedded in the report are included to enable readers to trace content back to its source here in Appendix A.

# A.1 Metric #1: The Fraction of Customers and Total Load Served by Real-Time Pricing, Critical Peak Pricing, and Time-of-Use Pricing

## A.1.1 Introduction and Background

Historically, service providers have set prices on a flat-rate basis, unaffected by the time the energy is used by customers or by the time-varying cost to the operator to supply the energy. The flat-rate system, while simple to understand and communicate to customers, does not motivate consumers to minimize their consumption of energy during peak periods when the cost to supply the power is at its highest point. Smart grid implementation promotes further transition from traditional flat rate pricing schemes to more flexible rate options such as time-of-use pricing (TOU), critical-peak pricing (CPP) and real-time pricing (RTP). Implementation of such tariffs has been forecasted to offset between 38,000 and 82,000 megawatts (MW), or 4 to 9 percent of U.S. peak electricity demand by 2019.[1]

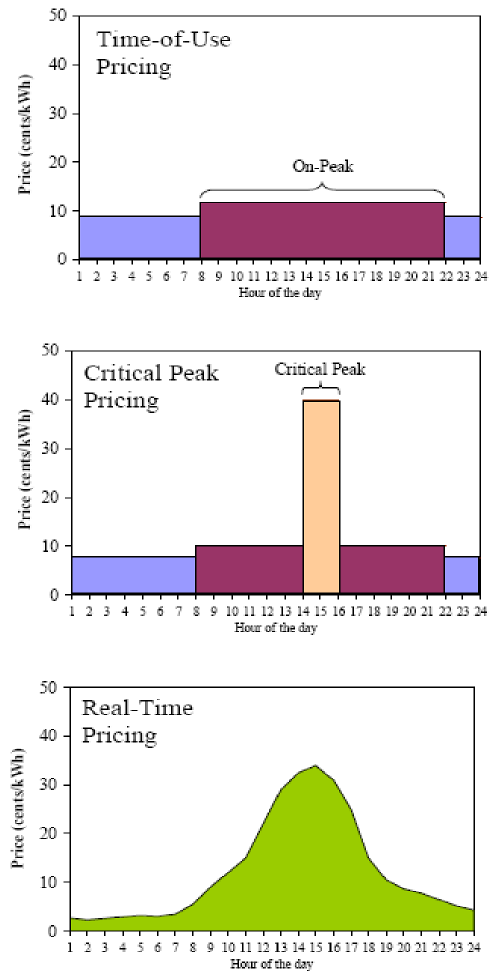



**Figure A.1**. Examples of Dynamic Pricing Tariff Structures

There are three principal pricing or tariff types covered in this section, as presented in Figure A.1.[2] TOU tariffs incentivize customers to permanently alter their energy consumption by using static price rates that are different during peak and off-peak periods, and sometimes vary by season. In contrast to a static system, implementation of advanced metering infrastructure (AMI) and other demand-side equipment allows utilities to move toward demand response tariffs such as CPP and RTP, which incorporate dynamic pricing structures that can be monitored and changed at intervals[3] such as 15 minutes. CPP tariffs are designed to adjust rates during higher critical-peak periods, but are limited to a small number of hours on specific, predetermined days.

[1] FERC – Federal Energy Regulatory Commission. 2010. *National Action Plan on Demand Response*. Staff Report, Docket Number AD09-10, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf (undated webpage).

[2] FERC – Federal Energy Regulatory Commission. 2008. *Assessment of Demand Response & Advanced Metering*. Staff Report, Docket Number AD-06-2-000, revised December 2008, Washington, D.C. Accessed November 6, 2008 at http://www.ferc.gov/legal/staff-reports/demand-response.pdf (undated webpage).

[3] FERC – Federal Energy Regulatory Commission. 2011. *Assessment of Demand Response & Advanced Metering*. Staff Report, Docket Number AD-06-2-000, Washington, D.C. Accessed January 24, 2012 at http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf.

Under RTP, prices vary at hourly or even shorter intervals, based on the day-of (real-time) or day-ahead cost of power to the service provider. Prices fluctuate throughout the day, with the highest prices set during peak periods. RTP tariffs are the most dynamic of the three pricing structures, and are therefore most dynamically responsive to peak-period consumption and energy costs. Adoption of dynamic pricing tariffs is designed to be revenue neutral for utilities, meaning an increase of the retail electricity price during peak periods would be offset by a decrease in price during off-peak times. All forms of dynamic pricing require installation of AMI, including smart meters that allow two-way communication between service providers and consumers (See Metric 12, Advanced Meters).[4]

An element encouraged by dynamic pricing, "demand response" refers to changes in energy consumption by end-users in response to electricity costs that vary over time or to incentives from energy providers, or when system reliability is jeopardized. This can include consumption behavior changes in response to pricing signals, but could also indicate participation in other demand-side initiatives, such as scheduled load reduction programs or other curtailment programs. Many demand response programs are structured for commercial and industrial customers as opposed to residential customers. According to the Federal Energy Regulatory Commission (FERC), implementation of smart grid technologies allows full realization of dynamic pricing and demand response through the following:

- automatically adjusting energy prices during peak hours or situations (dynamic pricing)
- allowing customers to manually respond to dynamic pricing by adjusting thermostats or changing peak consumption patterns
- allowing customers to automatically respond to dynamic pricing through automated technology, such as programmable communicating thermostats and smart appliances
- direct load control by utilities
- interruptible tariffs
- backup generation
- permanent load shifting
- supporting plug-in electric vehicles.[5]

### A.1.2 Description of Metric and Measurable Elements

*(Metric 1.a) The fraction of customers served by RTP, CPP, and TOU tariffs.*

*(Metric 1.b) The fraction of load served by RTP, CPP, and TOU tariffs.*

### A.1.3 Deployment Trends and Projections

FERC collects the most comprehensive data on trends in dynamic pricing programs. Starting in 2006, FERC distributed a biennial survey to gather information on AMI and demand response programs. The survey also includes specific questions regarding dynamic pricing tariffs and programs. Survey

[4] Static pricing structures like TOU do not require AMI, but can benefit from it because of lowered data collection costs relative to older meters that require field visits by meter readers.
[5] FERC 2011.

results from the 2006, 2008, and 2010 reports are presented in Figure A.2. For the 2010 survey, FERC altered the way respondents could answer questions about specific demand response programs with the objective of aligning FERC and Energy Information Administration (EIA) data collection efforts. Thus, the definition of AMI, along with the classification of demand response programs, has been changed. In previous surveys, respondents could assign many classifications to one type of demand response program, which, according to FERC, could have resulted in double-counting of dynamic pricing and demand response programs in the 2006 and 2008 surveys.[6] For the 2010 survey, however, respondents could only use one classification for a program type. This change is partially responsible for the decrease in dynamic pricing programs (indicated in Table A.1) between 2008 and 2010.

In 2010, 53,063 MW of demand response (dynamic pricing, direct load control, and interruptible tariffs) was available in independent system operator and regional transmission organization markets, up from 37,355 MW in the 2008 survey and 29,635 in the 2006 survey.[7] Figure A.2 illustrates the MW growth in available demand response resources between 2006 and 2010 as reported by FERC.[8] These data are presented as the total potential peak load reduction from demand response programs. Demand response includes any change in electric use by demand-side resources in response to price changes, incentives to lower consumption or when system reliability is jeopardized.

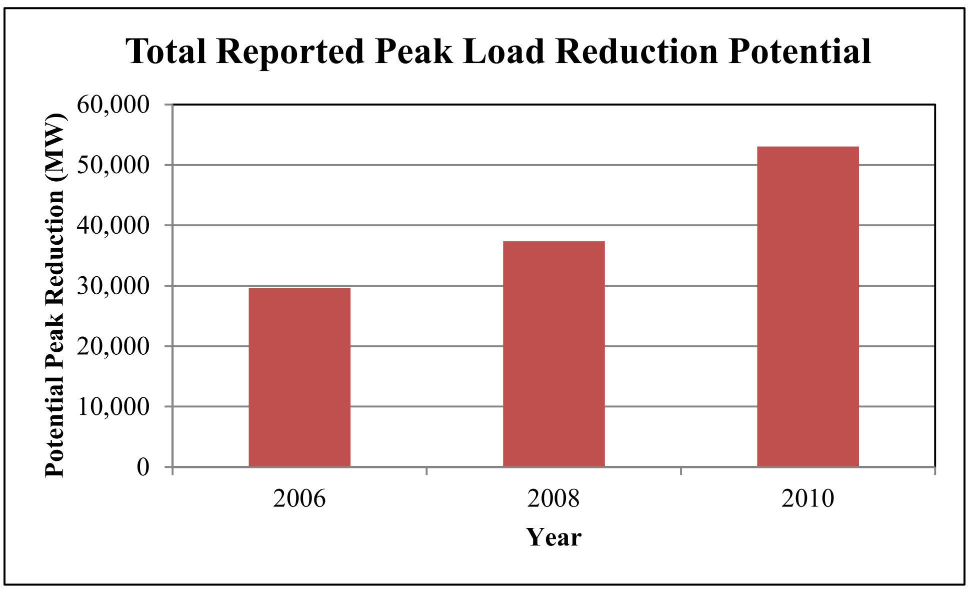



**Figure A.2**. Total Reported Potential Peak Load Reduction in 2006, 2008 and 2010 FERC Surveys

The 2010 FERC survey was distributed to 3,454 organizations in all 50 states. In total, 1,755 entities responded to the survey for a total response rate of 52 percent. In the residential sector, 169 entities reported offering TOU rates, down from 241 in 2008. In those participating utilities, approximately 1.1 million electricity consumers were signed up for TOU tariffs, representing approximately 1.1 percent of all residential, commercial and industrial customers (Table A.1). In 2010, customers were enrolled in CPP tariffs offered by 52 entities, as compared to 88 in 2008. As noted previously, FERC attributes the decrease in dynamic pricing programs primarily to the survey methodology changes discussed above.

[6] FERC 2011.
[7] FERC 2011.
[8] FERC 2011.

**Table A.1**. Number of Entities Offering and Customers Served by Dynamic Pricing Tariffs[9]

| Method of Pricing | Number of Entities in 2006 | Number of Entities in 2008 | Number of Entities in 2010 | Customers Served | |
|---|---|---|---|---|---|
| | | | | Number | Share of Total |
| Real-Time Pricing | 60 | 100 | 26 | – | – |
| Critical-Peak Pricing | 36 | 88 | 52 | – | – |
| Time-of-Use Pricing | 366 | 315 | 169 | 1,100,000 | 1.10% |

For this report, interviews were conducted with 30 municipal, public, investor-owned and nonprofit service providers (see Appendix B). The companies were asked two questions relevant to dynamic pricing. The first asked providers to identify the percentage of customers enrolled in RTP, CPP, and TOU pricing. Respondents were asked to segment their responses by customer type (i.e. residential, commercial, and industrial).

Table A.2 summarizes the results of the interviews as they relate to this first question. As shown, the participating electricity service providers indicated that approximately 2.67 percent of all residential customers were enrolled in TOU pricing. Approximately 4.56 percent of commercial customers and 24.75 percent of industrial customers were enrolled in TOU pricing. A higher percentage of commercial customers were enrolled in CPP (9.08 percent) relative to residential (3.91 percent) or industrial (4.05 percent) customers. For residential and commercial customers, there is extremely limited participation in RTP. Electricity service providers interviewed for this study reported that 3.4 percent of their industrial customers were enrolled in RTP.

**Table A.2**. Percentage of Customers Enrolled in Dynamic Pricing Tariffs

| Method of Pricing | Residential | Commercial | Industrial |
|---|---|---|---|
| Real-Time Pricing | 0.00% | 0.14% | 3.40% |
| Critical-Peak Pricing | 3.91% | 9.08% | 4.05% |
| Time-of-Use Pricing | 2.67% | 4.56% | 24.75% |

The companies were also asked whether they had automated response-to-pricing signals for major energy-using devices within a premise. The responses were:

- Thirteen companies (43.3 percent) indicated there were none.
- Seven companies (23.3 percent) indicated that automated price signals for major energy-using devices were in the development stage.
- Ten companies (33.3 percent) did not respond to the question.

[9] FERC 2011.

Electricity service provider investment supporting RTP, CPP, and TOU pricing has increased since the *American Recovery and Reinvestment Act of 2009* (ARRA). ARRA allocated $4.5 billion in grants to invest in smart grid technologies and electricity transmission infrastructure with a requirement for recipient co-funding, resulting in total investment of approximately $10 billion. ARRA investments in AMI have made time-based rate programs available to more than three million customers, expanding the number of customers enrolled in time-of-use pricing by nearly 278,000.[10] Overall, market effects of dynamic pricing are still insignificant; FERC estimates that penetration in ten states is 1 percent or less, and only one state is estimated to have 2 percent penetration.[11]

Traditionally, RTP has been adopted more broadly in the commercial and industrial sectors, but residential sector adoption is also beginning to grow. In 2011, TXU Energy launched their Power*Smart* PM 24™ program, which allows residential customers to receive discounts in electricity prices for consumption during non-peak hours. The program has three tiers: peak, off-peak, and nighttime pricing, incentivizing consumers to move certain activities such as laundry, dishwashing, and electric vehicle charging to off-peak hours. Table A.3 presents TOU pricing levels for customers in the Oncor service regions, which include the Dallas/Fort Worth metropolitan area. Oncor is the transmission and distribution provider for TXU Energy in the regions identified above; both companies are held by Energy Future Holdings Corporation.

**Table A.3**. TXU Energy's Power*Smart* PM 24™ Program Prices for Oncor Service Area[12]

| Tier | Months | Hours | Rate per kWh |
|---|---|---|---|
| Nighttime | All year | 10 p.m. to 6 a.m. | $0.068 |
| Peak | May through October | Monday – Friday 1 p.m. to 6 p.m. | $0.219 |
| Off peak | All non-peak months | All other times | $0.092 |

Another example of residential TOU tariffs include Portland General Electric's (PGE's) Residential Time-of-Use program that allows customers to opt in to dynamic electricity pricing that varies between $0.04/kWh off peak to $0.13/kWh during peak hours.[13] PGE's program is an opt-in program available to any residential customers.

The smart grid provides consumers with more interaction with the electric system, greater control of this interaction, and more choice. One way consumers become integrated with smart grid technologies is through incorporation of in home displays (IHDs) that communicate energy consumption, variable pricing and system performance.[14] By 2030, it is estimated that 20 percent of residential customers will have an

[10] DOE – U.S. Department of Energy. 2012. Recovery Act Smart Grid Programs: Deployment Status. SmartGrid.gov, Washington, D.C. Accessed December 14, 2012 at http://www.smartgrid.gov/recovery_act/deployment_status (last updated December 13, 2012).
[11] FERC 2010.
[12] Business Wire. 2011. *TXU Energy Offers Deep Nighttime Discounts for Electricity*. Accessed May 15, 2012 at http://www.businesswire.com/news/home/20111117005294/en/TXU-Energy-Offers-Deep-Nighttime-Discounts-Electricity (undated webpage).
[13] Portland General Electric. 2012. *Residential Time-of-Use Pricing*. Accessed May 15, 2012 at http://www.portlandgeneral.com/residential/your_account/billing_payment/time_of_use/pricing.aspx (undated webpage).
[14] EPRI – Electrical Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed June 20, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.

IHD, costing between $20 and $40 per unit, with a total cost of approximately $1.4 to 2.9 billion.[15] As technology continues to evolve, it is likely that more advanced applications allowing consumers to monitor their home energy consumption will advance in the marketplace. For example, General Electric's Nucleus Energy Manager is a software program that allows customers to monitor electricity consumption and rates. Using the program in combination with smart meters and smart appliances, consumers can monitor and control the performance of their appliances through their computer or smartphone.[16]

A recent study conducted for Detroit Edison, a subsidiary of DTE Energy, found that full deployment of a combination of TOU and CPP pricing schemes has the potential to offset as much as 36 percent of peak-hour demand when coupled with enabling technologies such as AMI.[17] Savings for DTE Energy from a TOU/CPP program combined with enabling technologies could amount to $633 million. This value would decrease to $399 million without the enabling technologies (for the DTE Energy service area),[18] thus indicating higher consumer participation when given dynamic pricing signals.

For many commercial and industrial customers, utilities are beginning to require participation in TOU pricing programs. For example, Pacific Gas and Electric (PG&E) transitioned large commercial and industrial customers (≥200 kW demand for three or more months) over to TOU pricing in 2011. In 2012, small businesses (up to 200 kW demand for three or more months) were also converted. Both plans combine TOU pricing with CPP on 9–15 specific event days during the year.[19] PG&E offers bill protection and day-ahead pricing signals for participants. In 2010, PG&E large commercial and industrial customers experienced nine CPP event days. In total, these customers reduced average load by 3.9 percent or 23 MW total.[20]

#### A.1.3.1 Associated Stakeholders

There are a number of stakeholders with interest in the dynamic pricing of electricity:

- regulatory agencies considering AMI business cases and dynamic pricing programs and those who are interested in expanding the role played by demand response in the power industry;
- residential, commercial, and industrial end-users who could benefit financially through the deployment of RTP programs, but must overcome their aversion to risk associated with smart meter deployment to fully understand the benefits and complexity of dynamic pricing programs;
- electric-service retailers who carry out dynamic pricing programs. They need access to wholesale markets to allow them to structure incentive programs to consumers that offer them the means for a

---

[15] EPRI 2011.

[16] GE - General Electric. 2012. *GE's Home Energy Management System, Featuring Nucleus with Brillion Technology*. Accessed July 11, 2012 at http://www.geappliances.com/home-energy-manager/index.htm (undated webpage).

[17] Jongejan A, B Katzman, T Leahy, and M Michelin. 2010. *Dynamic Pricing Tariffs for DTE's Residential Electricity Customers*. University of Michigan, Ann Arbor, Michigan. Accessed June 19, 2012 at http://www.erb.umich.edu/Research/Student-Research/2010/DynamicPricingTariffs-wb.pdf.

[18] Jongejan et al. 2010.

[19] Pacific Gas and Electric. 2012. *Time Varying Pricing*. Accessed April 26, 2012 at http://www.pge.com/mybusiness/energysavingsrebates/timevaryingpricing/ (undated webpage).

[20] Bode J. 2011. *California Statewide Non-Residential Critical Peak Pricing 2010 Impact Evaluation*. Prepared by Freeman, Sullivan & Co, presented at the DRMEC Load Impact Workshop, April 26, 2010, San Francisco, California. Accessed April 26, 2012 at http://fscgroup.com/reports/DRMEC.pdf (undated webpage).

viable business model. They desire a level of consistency across the nation so the service offering can be replicated and efficiencies shared.

- distribution-service providers who could use dynamic pricing adders to address capacity issues, increase reliability, and utilize their assets more fully;
- balancing authorities and reliability coordinators who could use dynamic prices to mitigate congestion issues and address shortfalls in available generation capacity;
- wholesale electricity traders and market operators who can use price elasticity to balance supply and demand, providing for a more responsive energy market;
- products and services suppliers who are interested in providing the metering, communications, and interfaces with demand-side automation to support dynamic pricing programs;
- standards organizations, which need to attract stakeholders to develop and adopt standards for the interfaces between the technologies being selected to support dynamic pricing programs;
- policy advocates, including environmental organizations, who can benefit from dynamic pricing to provide alternatives for new-generation power plants and transmission;
- consumer groups who want to mitigate price increases;
- governmental, legislative and administrative branches that view dynamic pricing as a way to foster competitive markets and manage load while reducing the need to expand existing generation, transmission, and distribution infrastructure. They are concerned that consumers be treated equitably and will be better off with dynamic pricing than with the traditional flat-rate tariff.

#### A.1.3.2 Regional Influences

The potential peak load reduction associated with demand-response, load management and pricing programs by NERC region are presented in Figure A.3. Nearly every region in the U.S. expanded potential peak reductions associated with demand response programs between 2010 and 2012. ReliabilityFirst Corporation (RFC) remained the region with the highest level of peak load reduction registering 24.4 GW of peak load reduction potential, an increase of 8.5 GW. The majority of this growth is due to increased participation by demand response resources in the PJM's forward capacity market. SERC Reliability Corporation reported the second highest level of potential peak load reduction by adding 3.7 GW. SERC and RFC now account for 55 percent of U.S.-reported peak load reduction due to demand response programs. Due to a decline in potential peak load reported by several significant entities in New York, potential peak reduction declined in the Northeast Power Coordinating Council (NPCC) between 2010 and 2012.[21]

[21] FERC – Federal Energy Regulatory Commission. 2012. *Assessment of Demand Response & Advanced Metering.* Staff Report, Washington, D.C. Accessed June 24, 2014 at http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf.

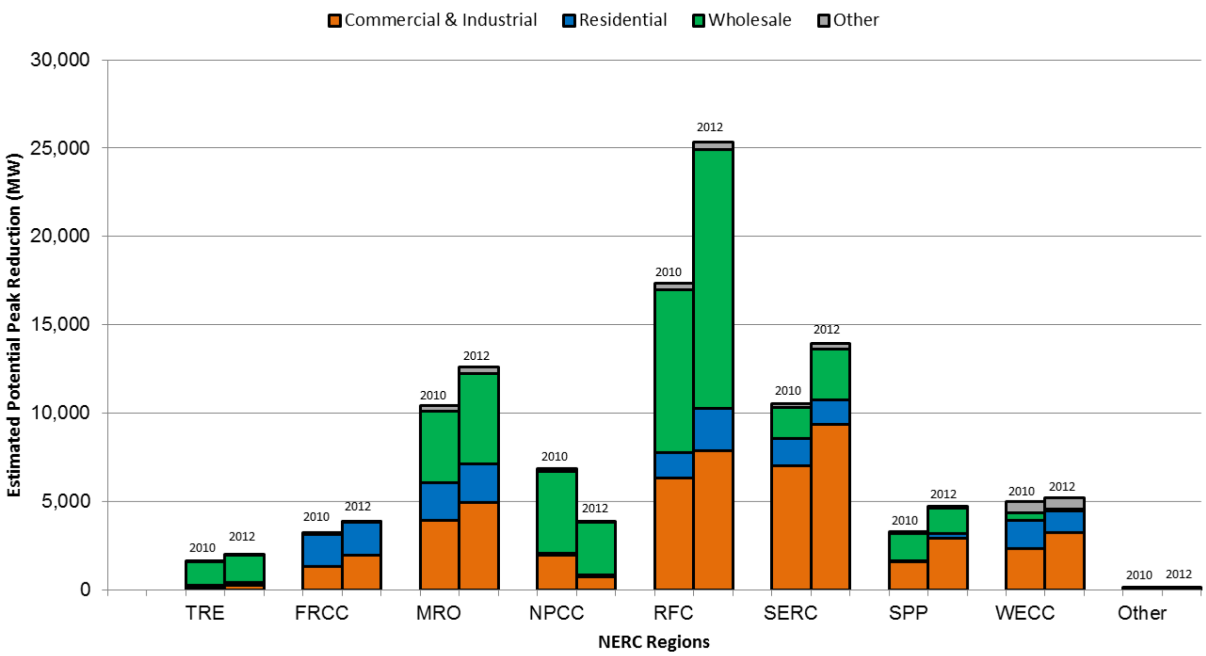



**Figure A.3**. Potential Peak Load Reduction by Region and Customer Class in 2010 and 2012

### A.1.4 Challenges to Deployment

The remainder of this section outlines a number of technical and business/financial barriers to implementing dynamic pricing in the energy sector.

#### A.1.4.1 Technical Challenges

Technical barriers include those related to AMI, other infrastructure requirements, and the need to update billing systems. Utilities must be able to measure usage according to the programs offered, communicate pricing information, and update billing systems prior to deploying variable pricing programs, which require installation of AMI. Although smart meter deployment has increased since 2010, there is still a lack of AMI infrastructure, including communications systems and other enabling technologies (see Metric 12). Additionally, hardware and software applications are necessary to handle dynamic pricing and AMI, allowing consumers and service providers to communicate with each other and respond to dynamic tariffs.

#### A.1.4.2 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- There are significant costs to service providers when installing AMI and updated billing systems. Regulatory recovery of these costs can be a contentious issue (see Metric 4, Regulatory Recovery for Smart Grid Investments). Focusing on large industrial customers and commercial buildings reduces the cost on a per-MW basis.

- There may be a self-selection bias in voluntary programs as customers who use less power during peak periods are more likely to enroll in the program, thus having less effect on load participation.
- Customers are not typically interested in complex dynamic pricing programs that must be monitored on an hourly or daily basis. However, with installation of automated controllers or automated agents, customers could anticipate and take advantage of price changes to reduce their energy costs.
- Many consumers believe there are privacy issues associated with further implementation of AMI. Consumers want to ensure their personal data collected through AMI will not be used to profile their energy usage or be distributed to other parties.
- Energy consumers are often averse to risk, and the assistance now offered by most service providers to protect them from price volatility may be perceived as inadequate.
- There may still be much uncertainty about what price level would be low enough to draw consumers to dynamic pricing simply because consumers must find it worthwhile to take the extra effort to set up their system to take advantage of dynamic pricing. Longer-duration studies are needed that evaluate the quality and quantity of data and the price levels needed to entice consumer response.

### A.1.5 Metric Recommendations

Future measurements should consider breaking down the metric by customer type (e.g., residential, industrial, commercial) to provide greater clarity into consumer response to dynamic tariffs. In addition, data are needed to measure the fraction of load served by dynamic pricing as outlined in Metric 1.b. A series of questions designed to address this issue has been developed for the EIA. The EIA is considering adding questions relevant to this metric to its EIA Form 861, *Annual Electric Power Industry Report*, for implementation in 2014. Any relevant data collected by EIA through its Form 861 survey should be considered in future dynamic pricing metric reports.

## A.2 Metric #2: Real-Time System Operations Data Sharing

### A.2.1 Introduction and Background

The term “smart” as applied to the power grid means there have been changes in the way information is used in the operation of the system. In a smart grid, data collected at any level of the system, from customer metering to distribution, transmission, generation status and even market operations, may be pertinent to improving operations at any other level. Thus, sharing data in a timely fashion, in near-real time, with all those with a need or right to know, is an essential ingredient of a smart grid.

As a practical matter, data that may be used to improve operations requires some form of communications system, usually connecting a remote location to an operational center. If the center in question is owned and operated by the same entity that owns and operates the source of the data, communicating the data will meet no institutional barrier. If the ownership is different, there may be reasons based on competition that make such a transfer of information less likely. Since the operation of the transmission grid, which is highly interconnected and has multiple owners, calls for exactly this kind of transfer, we concentrate in this metric on progress in increased levels of real-time data sharing.

“Real time” as used in this report means operational updates on time scales that may vary from sub-second to a few minutes. This metric focuses on sharing data between parties at the operations level of the bulk transmission grid, as opposed to sharing information within an electricity service provider.

Within an electricity service provider’s operations territory, it can be reasonably assumed that data is shared, or could be shared, to the extent required to effect economic operation and maintain system stability and reliability; that is, the “right to know” within the electricity service provider is implicit. Data sharing within the electricity service provider is limited primarily by the difficulty and cost of connecting applications to sensor networks and databases.

#### A.2.1.1 Explanation of Balancing Authority and Reliability Coordinator Functions

The electric power system balances its load and generation by observing the frequency. If the frequency is high, there is more generation than load, and generation will be reduced. If the frequency is low, load is greater than generation, and generation will be increased. The decisions to make these changes are made by entities called balancing authorities (BAs). BAs must maintain the grid’s physical integrity and adhere as closely as possible to the agreed-upon schedule for dispatch of generation, imports, and exports. That schedule means, of course, that the exchange of power between different BAs is something decided in advance, so that operation can be planned across an area larger than a single BA. Entities known as reliability coordinators (RCs) are needed to coordinate the actions of the various BAs to maintain overall system reliability. The RCs are essential to enable the transmission grid to transfer power over long distances, something which neither its original design nor its management systems were built to support.

Figure A.4, adapted from NERC,[22] shows the BAs as black dots, with paths for power flow between them. The diode symbol on some of the lines represents an ac/dc converter station. The figure shows the purview of members of the North American Electric Reliability Corporation (NERC) Reliability Coordinator List:

- Florida Reliability Coordinating Council (FRCC),
- Midwest Reliability Organization (MRO),
- Northeast Power Coordinating Council (NPCC),
- Reliability First Corporation (RFC),
- SERC Reliability Corporation (SERC),
- Southwest Power Pool (SPP),
- Texas Regional Entity (TRE),
- Western Electricity Coordinating Council (WECC).

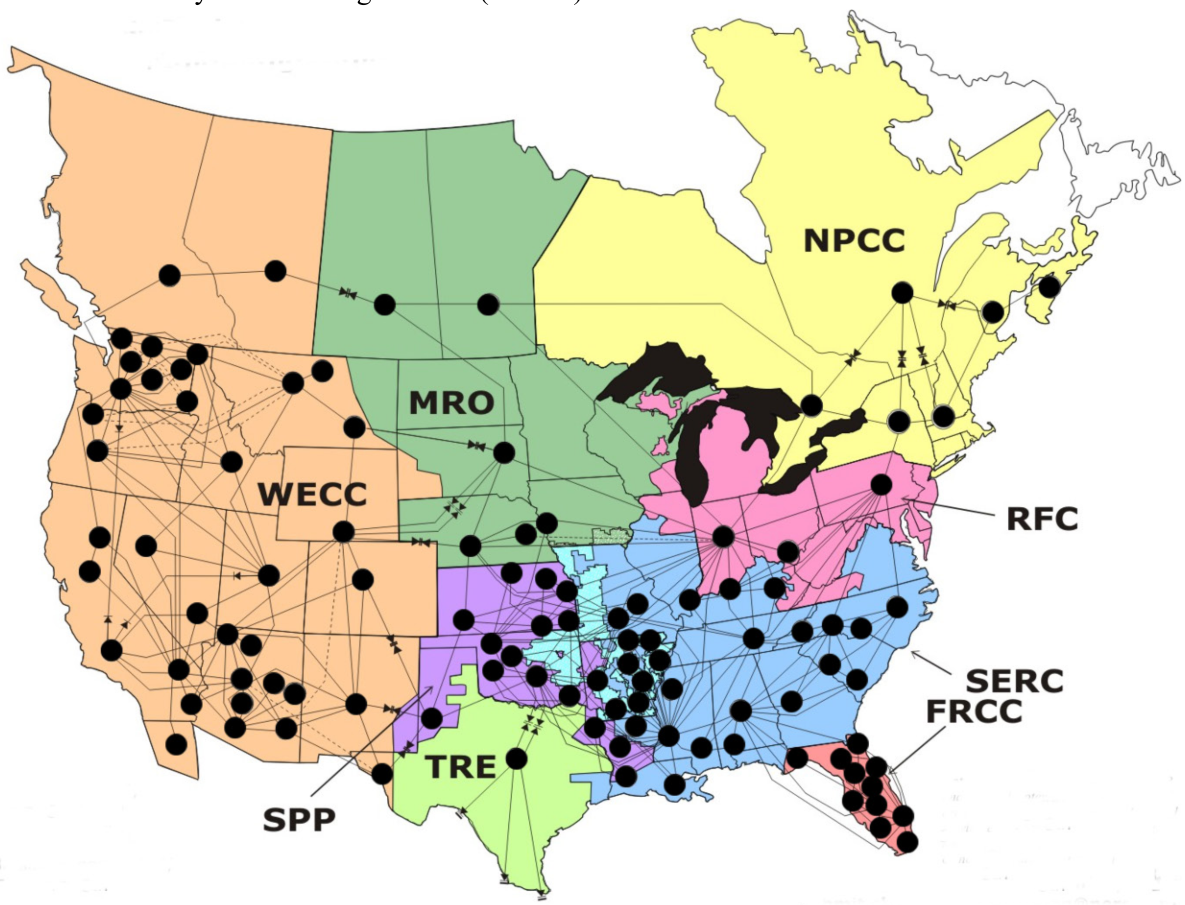



**Figure A.4**. NERC Regions and Balancing Authority Map

---

[22] NERC – North American Electric Reliability Corporation. 2012. *Regions and Balancing Authorities*. Princeton, New Jersey. Accessed July 26, 2012 at http://www.nerc.com/AboutNERC/keyplayers/Pages/Regional-Entities.aspx (last updated July 25, 2012).

### A.2.1.2 Historic Drivers for Improving Real-time Data Exchange

Two wide-area blackouts in the Western Interconnection in 1996[23] and the 2003 blackout in the Eastern Interconnection[24] showed how problems that originated in one area of the grid could cause blackouts in other widely separated areas. One of the causes of the widespread nature of the blackouts was that there was no way for operators to see the problem coming; they had no basis for acting to limit the disturbance.

An investigation was conducted jointly by the U.S. DOE and the FERC after the 2003 blackout. It supported the view that the event was caused partly because the operators who monitor the system were not aware of deteriorating conditions. The investigation also found that technology existed that could have been used for real-time monitoring. New technologies could enhance system integrity and improve operator awareness, and would consequently reduce the potential for future blackouts.[25] DOE and FERC concluded that an interconnection-wide monitoring system would be beneficial by providing real-time system data. Standardized data storage and visualization features would allow operators and dispatchers to access common information.[26]

### A.2.1.3 Implementation of Interconnection-Wide Transmission Monitoring

Supervisory control and data acquisition (SCADA) is the traditional means of gathering data for system operation. The data is typically scanned every few seconds. In a wide-area monitoring scheme, this data will be supplemented by what is called phasor data. These new measurements are obtained from what are known as phasor measurement units (PMUs). These devices provide information that has not been previously available. They make measurements of voltage and current waveforms, and furnish time-synchronized and time-stamped values.

Phasor data supplements SCADA data, but is not merely a more rapid version of the same thing. The readings from PMUs include information about the phase and frequency in the system and it time-tags all measurements to a standard based on the Global Positioning System. The current applications that use phasor data do not have the same comprehensive coverage provided by SCADA. Data as of 2010 was reported from a relatively sparse network of PMUs; the number has grown quickly due to Smart Grid Investment Grant (SGIG) Program funding. In 2011, there were approximately 200 PMUs installed nationwide: the North American SynchroPhasor Initiative (NASPI) estimated that number would grow to well over 1,000 PMUs by 2014, including approximately 866 funded through the SGIG matching grant program.[27] The NASPI estimate has proven accurate. As of September 2012, the number of SGIG-

---

[23] NERC – North American Electric Reliability Council. 2002. *1996 System Disturbances: Review of Selected 1996 Electric System Disturbances in North America*. Princeton, New Jersey. Accessed November 3, 2008 at http://www.nerc.com/pa/rrm/ea/System%20Disturbance%20Reports%20DL/1996SystemDisturbance.pdf (undated webpage).

[24] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.* Accessed November 3, 2008 http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf (undated webpage).

[25] DOE and FERC – U.S. Department of Energy and the Federal Energy Regulatory Commission. 2006. *Steps to Establish a Real-Time Transmission Monitoring System for Transmission Owners and Operators Within the Eastern and Western Interconnections: A Report to Congress Pursuant to Section 1839 of the Energy Policy Act of 2005*. Washington, D.C. Accessed October 21, 2010 at http://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/final_1839.pdf (undated webpage).

[26] DOE and FERC 2006.

[27] See Silverstein A. NASPI Update to the NERC Planning and Operating Committee, "NASPI Update and Technology Roadmap." December 2011, at https://www.naspi.org/site/Module/Resource/Resource.aspx. Accessed June 2012.

funded installations of PMUs had reached 546 units. The total number of networked PMUs in the U.S. had grown to nearly 1,700 by December 2013.[28] PMU data is being used to provide situational awareness and early warning of stability and reliability issues. They have also proved their value in post-event analysis.

Eventually, more-comprehensive reliability analysis tools will be available, based on broadly sharing data. Such tools may lead to increased utilization of wide-area control schemes, and allow dynamic adjustments, depending on the state of the grid. This capability would allow realization of new self-healing functions at the transmission level.

The transmission system is largely self-healing already. That is the nature of a system of lines configured as a network and equipped with the sophisticated protective relaying that is used. Faults occur and are automatically cleared. What will change is that the system may be able to respond to problems other than faults. The original cause of a blackout may be a fault (perhaps a tree comes into contact with a line), but that is readily cleared by the protective relaying. However, it may be that the line remains out of service. While that does not constitute a fault, it does change the operating conditions in the power grid, and it may contribute to other problems. The situational awareness aspect of PMU data is aimed at this kind of challenge.

### A.2.2 Description of the Metric and Measurable Elements

The metrics in this section address 1) the extent of sharing of SCADA information from BAs upward to RCs and back to the BAs, and 2) the extent of institutionalized sharing of synchrophasor data among utilities, BAs, and RCs.

*(Metric 2.a) Total SCADA points shared per substation (ratio).* The number of SCADA transmission-grid measurement points from grid assets that are shared by BAs with RCs, plus the number of SCADA measurement points shared by the RCs with BAs, divided by the number of substations:

(Total_Points_BAs→RCs + Total_Points_RCs→BAs) / Total_Substations

- *Total_Points_BAs→RCs*: the number of transmission-grid measurement points (e.g., voltage, power flow, etc.) from grid assets routinely shared by a control area with the RC responsible for supervising its region. A larger number shows that a more complete picture of grid status is being shared with the RC. The term "measurement point" corresponds to a sensor, not its time-series output; i.e., each sensor counts as "one" regardless of how often it is scanned. The phrase "from grid assets" is intended to prevent duplicate counts of a single measurement point, to which adjoining BAs jointly have access and which they forward to the RC.
- *Total_Points_RCs→BAs*: the number of transmission-grid measurement points routinely shared by the RC back to the BAs under its purview. The RC may share a set of data points with each of the BAs; each measurement point shared counts as "one" regardless of how many BAs receive it. This definition prevents counting the measurement point once for each of the many BAs that receive it. This definition presumes that if a measurement point is shared with one BA, it would be available to all of them. By adding the measurement-point data shared in each direction, there is an implicit

[28] Silverstein, A. 2013. *NASPI and Synchrophasor Technology Program.* Presented at NERC OC-PC Meetings. December 2013. Atlanta, GA.

"perfect score" for a measurement point of exactly two, representing full two-way data sharing. If state estimates based on the data are shared by the RC, rather than raw data, then this should also be counted as full two-way data flow.

- *Total_Substations:* The denominator of the metric is defined as the total number of substations within the BAs supervised by the RC. This is chosen instead of the number of busses used to model the system because it is less ambiguous.

Metric 2.a can be used at any level of the grid, but should be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

*(Metric 2.b) Fraction of transmission-level synchrophasor measurement points shared multilaterally (%).* The fraction shared is the number of phasor measurement points routinely shared via a multilateral institutional arrangement, divided by the total number installed in a region of the power grid:

Total_Phasor_Measurment_Points_Shared / Total_Phasor_Measurement_Points

- *Total_Phasor_Measurement_Points_Shared:* one count for each measurement from each transmission-level PMU or equivalent that is routinely shared via a multilateral institutional arrangement. This definition intentionally excludes bilateral arrangements because they are difficult to track, are less likely to persist over time, and may not be comprehensive.

- *Total_Phasor_Measurement_Points:* one count for each measurement from each PMU or equivalent installed on the grid at voltage levels above distribution voltage. Many new grid-sensing, control, and protection devices have PMU capabilities built in; if they are installed on the distribution system, they would not be counted.

Metric 2.b can be derived for any region of the grid, but will be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

### A.2.3 Deployment Trends and Projections

Interviews conducted for this report to indicate data sharing (see Appendix B) show a weighted average (weighted by number of substations) of 18 percent of SCADA points and 67 percent (weighted by number of customers) of PMU measurement points. These figures were not reported in the 2010 Smart Grid System Report (SGSR), but can be considered moderately wide sharing of data, especially the PMU data.

A survey by Newton-Evans Research[29] indicates there is significant sharing of measurement, analysis, and control data from electricity service provider control systems for transmission and distribution, energy management systems (EMS) and distribution management systems (DMS) with other grid entities, including regional control centers and other electricity operators. The survey was completed by over 100 utilities in the U.S. and Canada, representing a total of 66,129,387 end-use customers. Utilities were asked to report the amount of EMS/SCADA/DMS systems in place, and specify the type of system. Results from the 2010 survey are represented in Figure A.5.

[29] Newton-Evans Research Company. 2010. *Market Trends Digest*. Endicott City, Maryland. Accessed November 29, 2010 at http://www.newton-evans.com/mtdigest/mtd3q10.pdf (undated webpage).

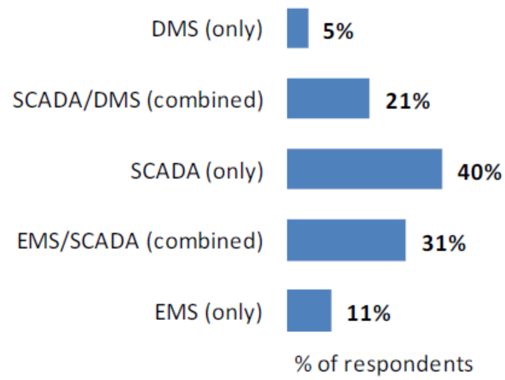



**Figure A.5**. Current Installations of EMS/SCADA/DMS Systems by Type[30]

The data for Metric 2.b was obtained from the participants in NASPI. NASPI is a joint DOE-NERC effort to facilitate and expand the implementation of phasor technology for enhancing power system situational awareness and reliability. NASPI has attempted to operate a PMU registry, but has not been supported in this effort by many of the owners of PMUs. Interestingly, the Western Interconnection is also now maintaining a PMU registry of its own. Figure A.6 below illustrates the networked and installed PMUs throughout the United States as of March, 2012.

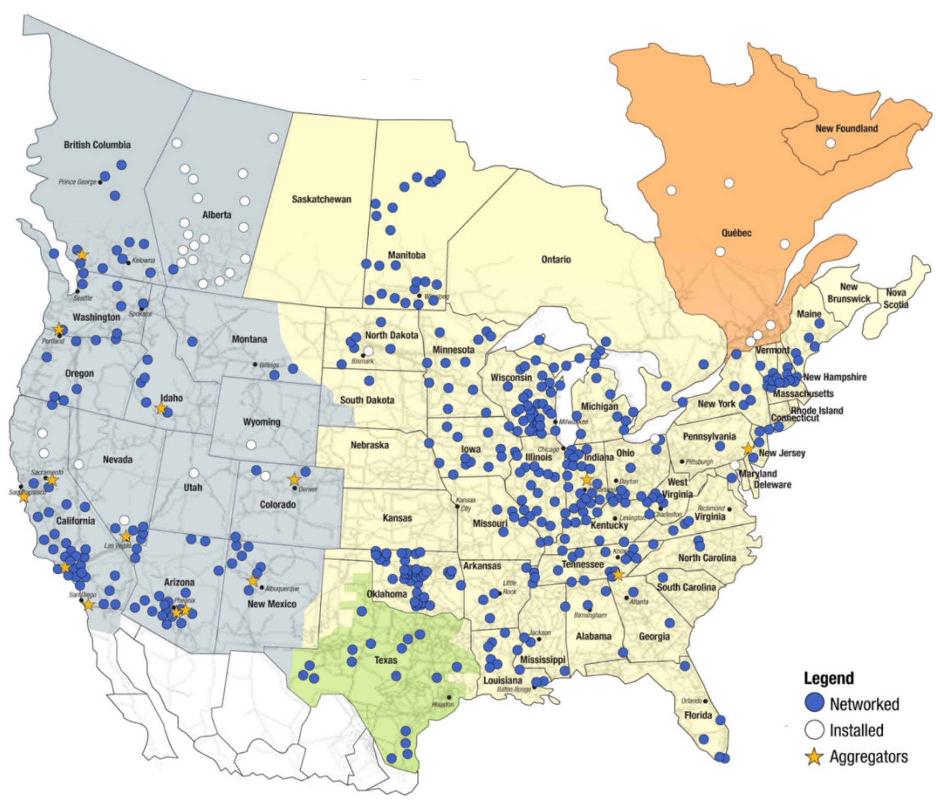



**Figure A.6**. Phasor Measurement Units in the North American Power Grid, March, 2012[31]

[30] Newton-Evans 2010.

#### A.2.3.1 ARRA Funding to Dramatically Increase PMU Count

The SGIG program, funded by the *American Recovery and Reinvestment Act of 2009* (ARRA), provided matching grants for investment in advanced metering infrastructure and customer systems, electric distribution systems and the electric transmission system. Table A.4 presents data on installations, project cost and total number of projects underway through the SGIG program relating to electric transmission system assets by the end of September 2012.[32] As shown, the SGIG had funded the installation of 546 PMUs at a total cost of $40.5 million and 94 phasor data concentrators at a cost of $10.2 million. As of September 2012, ARRA-funded SGIG projects targeting transmission system assets had totaled approximately $281.5 million. In addition, the SGDP had co-funded the installation of an additional 23 PMUs as of September 30, 2012.[33]

**Table A.4**. SGIG Program Electric Transmission Asset Expenditures[34]

| Electric Transmission System Assets | Quantity | Incurred Cost | Number of Entities Reporting |
|---|---|---|---|
| PMUs | 546 | $40,553,730 | |
| Phasor Data Concentrators | 94 | $10,202,758 | |
| IT[(a)] Hardware, Systems, and Applications that Enable Transmission Functionalities | | $40,236,0274 | 31 |
| Advanced Applications | | $15,778,035 | 14 |
| Other Transmission Related Costs | | $174,772,069 | 22 |
| Total Transmission Installed Cost | | $281,542,619 | 22 |

(a) IT = information technology

#### A.2.3.2 Distribution-Level SCADA Data Use and Sharing

The SCADA test bed evaluation report[35] found significant effort in the electricity service provider sector to improve security in substations. Utilities were replacing electromechanical relays with digital relays and moving to the latest levels of automation. As substation automation is pursued, company standards are emphasizing cyber security, new standards and the current best practices. The study showed that standards have begun to address automation.

#### A.2.3.3 State-Level Influence on Real-Time Data Sharing: California

California's power system is in a state of transition from the vertically integrated utilities that preceded deregulation to an independent system operator (ISO) managing competitive energy markets. A

---

[31] EIA – U.S. Energy Information Administration. 2012. *New Technology Can Improve Electric Power System Efficiency and Reliability*. Washington, D.C. Accessed July 25, 2012 at http://www.eia.gov/todayinenergy/detail.cfm?id=5630# (last updated March 30, 2012).

[32] Bossart, S. 2013. Personal Communication. Data Compiled from ARRA Recipients Federal Financial Reports (FFR) SF-435. April 26, 2013.

[33] Wang, W. 2013. Personal Communication. *Data Compiled from ARRA Recipient's Federal Financial Reports (FFR) SF-435*. May 31, 2013.

[34] DOE 2012.

[35] INL – Idaho National Laboratory. 2009. *National SCADA Test Bed Substation Automation Evaluation Report*. INL/EXT-09-15321, Idaho Falls, Idaho. Accessed October 21, 2010 at http://www.inl.gov/technicalpublications/Documents/4374057.pdf (undated webpage).

project[36] as part of the California Energy Commission's Public Interest Energy Research (PIER) Program found that the traditional approach to reliability improvement—construction of new transmission lines—was being delayed by issues concerning the financing and recovery of transmission project costs. An alternative strategy, new investments in transmission monitoring infrastructure, should enable better management of reliability by system operators.

The PIER program led to first-ever demonstrations of two prototype real-time software tools allowing voltage security assessment and phasor monitoring, along with a scoping study on improving load and generator response models.

#### A.2.3.4 Stakeholder Influences

Aspects of the U.S. electrical transmission system are regulated on both the federal level (reliability and interstate commerce) and at the state level (siting, prudency of investment, rate recovery). Input and planning for the transmission infrastructure is conducted, in increasing levels of detail and ultimate authority, by groups of state/regional governments, regional RCs, regional transmission organizations or ISOs, and the utilities themselves. The planning and operation of the transmission grid involves the participation of a very large number of stakeholders as well.

Among the stakeholders identified in Section 1.3 of the main body of this report, the following have special interest in transmission-level real-time data sharing (Metrics 2.a and 2.b):

- transmission providers and BAs – The metrics provide a benchmark for transmission providers and BAs sharing information that raises their situational awareness, can increase reliability, and may eventually result in wide-area control schemes that help realize the goal of a self-healing grid.
- reliability coordinators including NERC – The metrics provide a benchmark of progress toward increasing sharing of data by NERC's constituents. Data sharing helps NERC achieve its reliability goals. The existence of the metrics themselves could serve as motivation toward institutionalizing data-sharing mechanisms (especially for phasor data).
- products and service providers – Increased sharing of transmission data over wide areas opens up opportunities to develop new analysis applications driven by the data, which in turn may help promote sales and installation of phasor-measurement-capable devices.
- local, state, and federal energy policy makers; policy advocates – The existence of the metrics helps them focus on and drive the institutionalization of data-sharing mechanisms.

Other stakeholders with less direct interest include:

- generation and demand wholesale electricity traders/brokers – They benefit from the more reliable electric grid that the sharing of data enables, because market-based dispatch is less often disrupted by operational contingencies.
- distribution-service providers – They benefit indirectly because the more reliable bulk power system that data sharing will enable causes less disruption to their distribution systems.

[36] Eto J, B Lesieutre, NJ Lewis, M Parashar, J Cole, and L Miller. 2008. *Real-Time Grid Reliability Management*. CEC-500-2008-049, prepared by Lawrence Berkeley National Laboratory for the PIER Transmission Research Program, California Energy Commission, Sacramento, California. Accessed October 21, 2010 at http://certs.lbl.gov/pdf/cec-500-2008-049-report.pdf (undated webpage).

- electric-service retailers and end-users – They benefit from being able to offer and obtain more reliable electric service.

#### A.2.3.5 Regional Influences

The metrics are measured for each interconnection because of the strong regional differences associated with the size and governance of each of the three interconnections. ERCOT is by far the smallest of the three in terms of population, number of substations, load served, and geographic area. It also has the most unified institutional arrangement, with ERCOT acting as the regional transmission operator and planner, the market operator, and the RC. As such, it has great authority to engage constituent utilities in integrating their transmission data. ERCOT installed 3 PMUs in 2008; since that time, PMU installations have more than quadrupled to 17 PMUs installed at 15 locations around Texas.[37]

The WECC is nearly as large in geographic area as the Eastern Interconnection, yet serves a significantly smaller population scattered in widely separated pockets. The wide separation of population centers and generation cause it to have special problems with low-frequency oscillations and dynamic stability. These were the issues that led to the 1996 blackouts. The WECC[38] was created in 2002 with a focus on wide-area issues associated with reliability. The blackouts were drivers for the WECC to be an early adopter of data-sharing arrangements. Of particular note with respect to Metric 2.b, members of the WECC were the early pioneers of phasor data collection and sharing even in the 1990s.

WECC's West-wide System Model concept that began in 2005 came to fruition with the issue of a Request for Proposals for a Base Case Coordination System[39] in 2009. Projects include 10- and 20-year transmission plans for WECC expansion of transmission planning activities, such as the creation of a Scenario Planning Group to facilitate stakeholder involvement.[40] This is an example of how data sharing enables increased levels of situational awareness that should result in higher reliability. This development will drive increased data sharing that should result in higher values for Metric 2.a. The SGIG program significantly affected WECC data-sharing technology installation efforts; a total of $108 million in investments by DOE and operating entities has been made for synchrophasor expansion.[41]

The Eastern Interconnection with its large area, dense population, and closer proximity of population centers to generation, has 13 RCs. The eastern grid is relatively "stiff" in that it does not exhibit the oscillatory behavior that the Western Interconnection does. The 1996 and 2003 blackouts clearly showed that such events can extend beyond even the larger areas of a single RC, yet the Eastern Interconnection

---

[37] Adams et al. 2012.

[38] WECC – Western Electricity Coordinating Council. 2010. *WECC Annual Review: January 2009 – July 2010*. Salt Lake City, Utah. Accessed October 26, 2010 at http://www.wecc.biz/library/WECC%20Documents/Publications/WECCAnnual.pdf (undated webpage).

[39] WECC – Western Electricity Coordinating Council. 2009. *Base Case Coordination System*. Salt Lake City, Utah. Accessed October 21, 2010 at http://www.wecc.biz/Planning/BCCS/default.aspx (undated webpage).

[40] Woertz B. 2010. *Scenario Planning Steering Group: What It Is and Why It's Important*. Western Electricity Coordinating Council, Salt Lake City, Utah. Accessed October 21, 2010 at http://www.wecc.biz/committees/BOD/TEPPC/SPSG/SPSG%20Update%20for%20Transmission%20Owners,%20Operators%20and%20Developers/Lists/Agendas/1/Transmission%20Owners,%20Operators%20and%20Developers%2006-08-2010.pdf (last updated June 8, 2010).

[41] Kosterev D. 2012. *Joint Synchronized Information Subcommittee*. Committee Report, prepared by Bonneville Power Administration for the Western Electricity Coordinating Council. Accessed July 25, 2012 at (uhttp://www.wecc.biz/committees/StandingCommittees/PCC/07182012/Lists/Minutes/1/2012-07%20WECC%20JSIS%20Report.pdfndated webpage).

does not have an organization like the WECC, an interconnection-wide institution charged with reliability, that can help drive data sharing. NASPI's Planning and Implementation Workgroup will develop and maintain a frequency response baseline for the Eastern Interconnection, as well as develop and maintain a baseline for inter-area power oscillations in the Eastern Interconnection.[42]

Partly as a result of the 2003 blackout, however, an Eastern Interconnection Phasor Pilot (EIPP) project was established, and the project has pioneered phasor data sharing with the use of phasor data concentrators that collect and archive data. The EIPP was subsumed to NASPI, which is attempting to formally institutionalize data sharing, among its other objectives.

### A.2.4 Challenges

#### A.2.4.1 Technical Challenges

The principal technical challenges involved with data sharing at the transmission level involves the level of effort to identify, configure, and maintain the data to be exchanged between parties. Standard protocols exist for inter-control-center site data exchange and phasor data exchange. Most suppliers of control center systems support these standards. However, complete, unambiguous interoperability requires significant processing and testing. Besides the data-exchange protocols, common naming conventions and unambiguous identity services would make integration and maintenance easier. Software interfaces that support publishing and interrogation services that are consistent with cyber security and information privacy policies (see Business and Financial Challenges, below) would reduce the manual labor necessary to support data sharing.

Situational awareness, and system operations applications such as state estimation, also require the sharing of system modeling data. Power systems are complex, and models must continually change as parts of the system are taken out of service temporarily or new construction is added. Ownership and responsibility rights are also continually changing and require periodic updates, otherwise data-sharing initiatives can be put on hold or discarded because the parties involved are not willing to support and exchange the requisite system models. Agreement on technical approaches and services can help reduce model maintenance and the burden of keeping neighbor models consistent.

#### A.2.4.2 Business and Financial Challenges

There are procedural, business, and privacy issues that hinder sharing of data and information collected by an electricity service provider with peers and higher-level grid RCs. Circumstances could also require sharing of information with non-grid entities, such as emergency-response centers or state and federal government agencies. Challenges to such data sharing include:

- competitive intelligence – could be used in corporate takeovers, service-territory takeovers, change to municipal service by cities or electricity service provider districts, or competition to serve areas of growth

[42] NASPI PITT – North American Synchro-Phasor Initiative Planning and Implementation Team. 2010. *North American Synchro-Phasor Initiative Planning Implementation Task Force: Mid-Term Workplan*. Accessed August 2012 at http://www.wecc.biz/committees/JSWG/08102010/Lists/Minutes/Forms/DispForm.aspx?ID=2 (last updated September 16, 2010).

- market intelligence – such as business actions that cause a change of service territory; market operators may be able to gather information to enhance their bidding strategies in wholesale markets, and regulated utilities want to limit this
- second-guessing and prudency reviews – potential for legal action from regulators and competitors
- financial penalties – in the form of fines from regulators, lawsuits from customers, and reduced incentive payments from regulators
- data security – potential highlighting of physical or control-system vulnerabilities.

When ARRA funds were allocated, DOE identified a number of challenges, including those listed above, related to PMU data sharing. To mitigate these barriers, the Office of Electricity Delivery and Energy Reliability proposed that NERC develop a comprehensive nondisclosure agreement and phasor network communication specification to ensure safe and effective sharing of data.[43]

### A.2.5 Metric Recommendations

The research team was not able to find data to measure the deployment trends for Metric 2.a. The review team had planned to acquire this information from key industry stakeholders, such as the Data Exchange Working Group (scope approved July 2011) or the Reliability Coordinator Working Group (scope approved September 2009) of NERC. A review of information from NERC's website on those groups found no information applicable to Metric 2.a. The Data Exchange Working Group has established the Interregional Security Network[44] for the exchange of data between RCs, but the research team found no report of the traffic on the network. That activity would not appear to be part of the scope defined for the working groups.

For Metrics 2.a and 2.b, it should be recognized that data exchange at the bulk grid/transmission level is only a means to an end; merely exchanging data does not accomplish anything. The end result is situational awareness leading to increased reliability and eventually a self-healing grid. If metrics could be developed that better represent the data being used, which applications it was being used for, and what the geographic/topological scales of the analyses are, these would better capture the intent of data-sharing metrics for the transmission grid.

A more pragmatic approach to replacing Metric 2.a would be to survey regional coordinators and/or balancing authorities about the visualization tools that their operators use to turn SCADA and PMU data into actionable information. The California ISO uses several tools of this nature. One such tool measures voltages and voltage reserves throughout the Western Interconnection. Diagnostic analysis is conducted to identify voltage irregularities and evaluate options to address them.

---

[43] OE – Office of Electricity Delivery and Energy Reliability. 2009. *Office of Electricity Delivery and Energy Reliability Recovery Program Plan*. Washington, D.C., p. 15. Accessed July 25, 2012 at http://energy.gov/downloads/office-electricity-delivery-and-energy-reliability-recovery-program-plan (last updated June 3, 2009).

[44] See, for example, http://www.nerc.com/docs/oc/twg/DEWG_Minutes_14Jul11-R1.pdf. Exhibit D of this document is the Scope statement of the Data Exchange Working Group. The Reliability Coordinator Working Group Scope is at http://www.nerc.com/comm/PC/Pages/Reliability%20Assessment%20Data%20Working%20Group%20(RADWG)/Reliability-Assessment-Data-Working-Group-RADWG.aspx.

## A.3 Metric #3: Standard Distributed Resource Connection Policies

### A.3.1 Introduction and Background

A key aspect in smart grid development includes connecting decentralized power sources, known as distributed energy resources (DER), to the grid. Lack of policies surrounding interconnection can result in delays, technical challenges and unnecessary expenses. In 2011, the EIA reported that 15,630 electricity service provider or customer-owned distributed generators were grid-connected in 2010, representing a total capacity of 4,971 megawatts (MW).[45] Figure A.7 illustrates the growth of grid-connected and non-grid-connected DER between 2006 and 2010.[46]

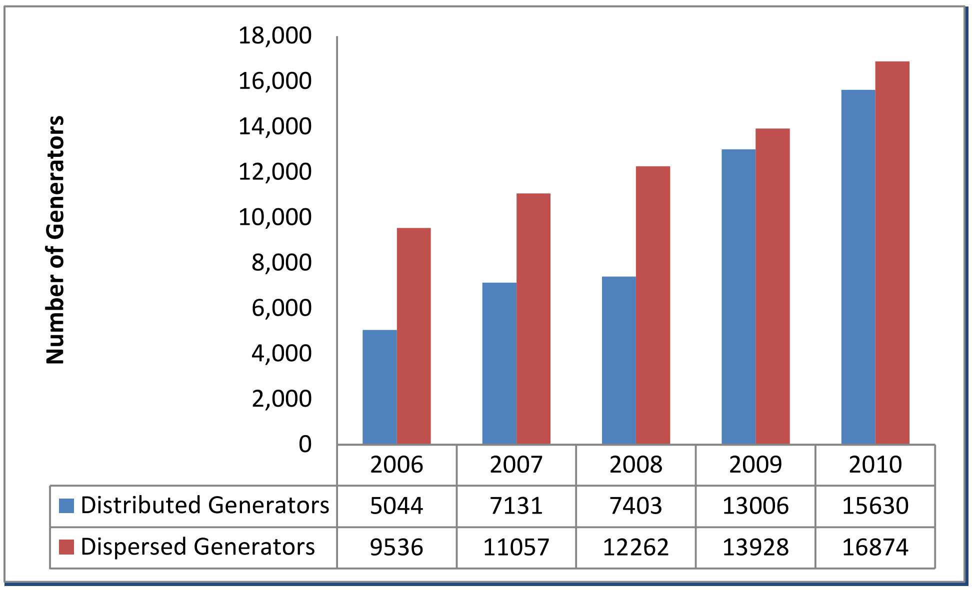



**Figure A.7**. Distributed and Dispersed Generation Growth (2006 to 2010)

Benefits of distributed power generation such as peak-load reduction, combined heat and power (CHP) generation, base load power generation and improved power quality can be realized by both consumers (residential, commercial, industrial) and service providers. In addition, increasing capacity of distributed renewable energy resources, such as photovoltaic, solar thermal and geothermal systems further illustrates the importance of interconnection policy development.

Federal legislation attempting to address interconnection issues emerged in progressively stronger language, resulting in the *Energy Policy Act of 2005* (EPAct 2005), which requires all state and non-state utilities to consider adopting interconnection standards based on the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547.[47] IEEE 1547, which was published in 2003, looks strictly at the

[45] EIA – U.S. Energy Information Administration (EIA). 2011. "Table 1.6.C, Total Capacity of Dispersed and Distributed Generators by Technology Type." In *Electric Power Annual 2010*. Accessed February 8, 2012 at http://www.eia.gov/electricity/annual/ (undated webpage).
[46] Dispersed generators, as defined by the EIA, are not connected to the grid while distributed generators are connected to the grid. Both types may be located at or near a consumer's residence, and either may be owned by customers or the utility.
[47] *Energy Policy Act of 2005,* Public Law 109-58, as amended, Section 1254 (16 USC 2621(d)). Accessed February 16, 2012 at http://energy.gov/eere/femp/downloads/energy-policy-act-epact-2005 (undated webpage).

technical aspects of DER interconnection, providing a standard that limits the negative impact of these resources on the grid. In September 2011, IEEE published Standard 1547.6, which provides recommendations and guidance on designing DER interconnection policies for secondary networks.[48]

In part to address some of the permitting aspects of interconnection, the Federal Energy Regulatory Commission issued Order 2006, which mandated that all public utilities that own transmission assets provide a standard connection agreement for small generators (under 20 MW).[49] To expand favorability of interconnection standards, the *Energy Independence and Security Act of 2007* (EISA) requires interoperability policies to accommodate consumer distributed resources, including distributed generation, renewable generation, energy storage, energy efficiency, and demand response.[50] To meet this requirement, the National Institute of Standards and Technology (NIST) released the *NIST Framework and Roadmap for Smart Grid Interoperability Standards*, version 2.0, early in 2012. One of the sixteen priority areas within the standards framework is recognition of distribution grid management from centralized and decentralized power sources.[51]

### A.3.2 Description of Metric and Measurable Elements

*(Metric 3) The percentage of utilities with standard distributed resource interconnection policies.*

The topic also discusses the commonality of such policies across utilities.

### A.3.3 Deployment Trends and Projections

As of May 2012, 43 states, Washington, D.C., and Puerto Rico have adopted variations of an interconnection policy, including eleven states that only have guidelines (AK, AR, DE, GA, KS, LA, MO, MT, NE, SC, WY). Distributed resource interconnection policies have been either implemented or expanded in seven states (AK, DE, IL, MT, NH, UT, WV) since the 2010 Smart Grid System Report (SGSR) was published, thus promoting the advancement of distributed generation technologies. By categorizing states based on their interconnection policies and identifying the number of utilities in each state, the research team was able to estimate the percentage of utilities with standard resource interconnection policies. Based on this approach, it is estimated that roughly 86.8 percent of utilities currently have a standard resource interconnection policy in place, compared to 83.9 percent in 2010 and 61.2 percent in 2008.[52] When weighted based on sales in each state rather than utility location, the interconnection rate is estimated at 87.8 percent. The United States Department of Agriculture's Rural Utility Service Loan Program requires all existing borrowers to have a current and publicly available

---

[48] IEEE – Institute of Electrical and Electronics Engineers. 2011. *IEEE Standard 1547.6: Draft Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Network*. Accessed February 6, 2012 at http://grouper.ieee.org/groups/scc21/1547.6/1547.6_index.html (undated webpage).

[49] "Standardization of Small Generator Interconnection Agreements and Procedures; Order on Rehearing.", Federal Energy Regulatory Commission. Order No. 2006-A, 70 FR 71760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005). Accessed February 16, 2012 at http://www.gpo.gov/fdsys/pkg/FR-2005-11-30/pdf/05-23461.pdf (undated webpage).

[50] *Energy Independence and Security Act of 2007 (EISA); Smart Grid Interoperability Framework.* Public Law 110-140. Section 1305 ( 42 USC § 17385). Accessed July 16, 2010 at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf (undated webpage).

[51] NIST – National Institute of Standards and Technology. 2012. *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0*. NIST Special Publication 1108R2, National Institute of Standards and Technology, Gaithersburg, Maryland. Accessed May 15, 2012 at http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf (undated webpage).

[52] EIA – U.S. Energy Information Administration. 2002. *Contact Information for Electric Utilities by State*. Washington, D.C.

policy regarding the interconnection of distributed resources. Rural Utility Service borrowers (this does not include grant recipients) serve customers in 46 states.[53]

As illustrated in Figure A.8, 12 states plus Puerto Rico have no limits on the size of system allowed within their programs, 18 states limit generator interconnection based on energy type or kilowatt (kW) capacity, and 13 states limit their standards to net-metering systems only. Since the 2010 SGSR was published, West Virginia and Alaska have added interconnection policies and numerous states have increased generator size limitations. Many states that have taken aggressive action on distributed generation interconnection policy have done so to incorporate grid-connected renewable energy to meet renewable portfolio standards or energy efficiency requirements.

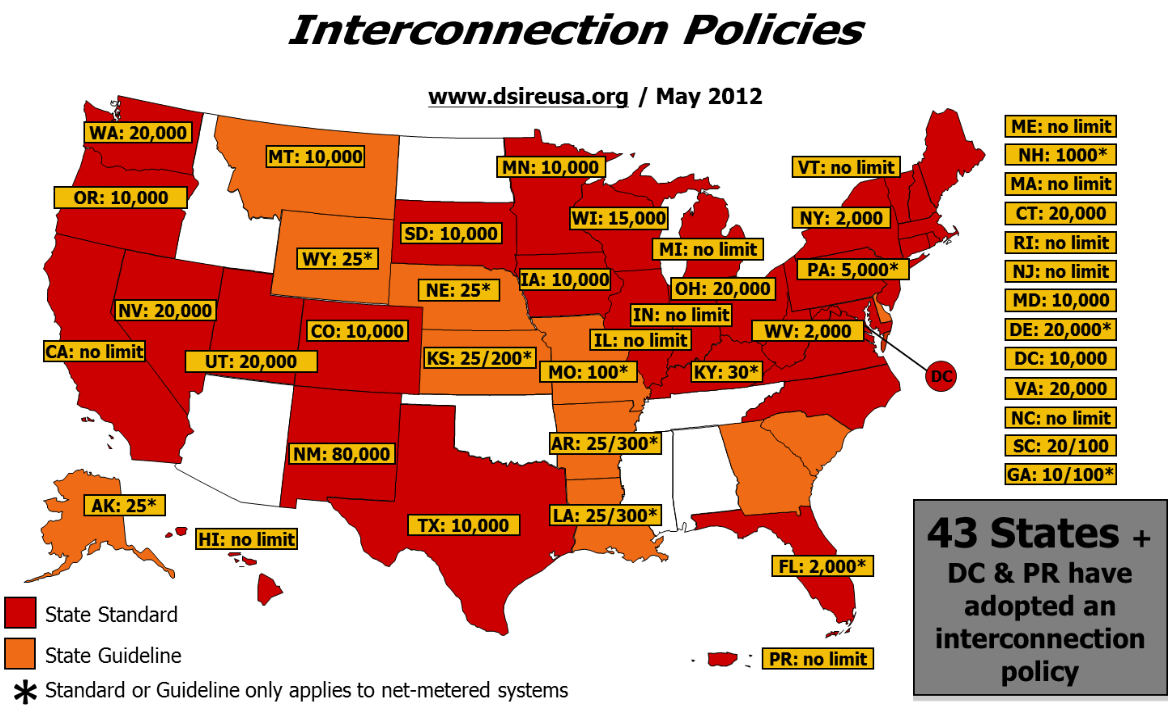



**Figure A.8**. State Interconnection Standards[54],[55]

In order for interconnection standards to be accepted by end users, states must draft them in a manner that encourages consumer participation. The Network for New Energy Choices (NNEC) have produced an annual report analyzing the favorability of state interconnection standards based on a 14-point numerical grading system that awarded points for active promotion and deducted points for discouraging DER advancement. Table A.5 identifies each category scored in the study.[56]

---

[53] USDA – U.S. Department of Agriculture. 2012. *Rural Development – RUS Electric Program*. Washington, D.C. Accessed May 15, 2012 at http://www.rurdev.usda.gov/UEP_Homepage.html (updated May 2012).

[54] DSIRE – Database of State Incentives for Renewable Energy. 2012. *Interconnection Standards*. Accessed May 15, 2012, at http://www.dsireusa.org/documents/summarymaps/interconnection_map.pdf (undated webpage).

[55] System capacity limits denoted in kW (numbers in blocks). States vary in how they structure their interconnection standards. Some are strict limits by customer type, e.g., residential and non-residential. No limit indicates there is no limit on the capacity size. Typically the state standards only impact investor own utilities.

[56] NNEC – Network for New Energy Choices. 2011. Freeing the Grid: *Best Practices in State Net Metering Policies and Interconnection Procedures*. Accessed June 19, 2012 at http://freeingthegrid.org/.

**Table A.5**. Favorability Scoring Categories

| NNEC Policy Grading Categories |
|---|
| Standard Form Agreement |
| Timelines |
| Individual System Capacity |
| Insurance Requirements |
| Eligible Technologies |
| Engineering Charges |
| External Disconnect Switch |
| Certification |
| Technical Screens |
| Network Interconnection |
| Interconnection Charges |
| "Breakpoints" for Interconnection Process |
| Dispute Resolution |
| Rule Coverage |

The grading system designed by NNEC (Table A.5) numerically evaluated 14 policy issues specific to interconnection, including technological considerations, system capacity, cost-effectiveness, insurance requirements, and timelines. The A-through-F grading system, presented in Figure A.9, was established based on the categories listed in Table A.5 and reflects an assessment of each state's policies based on these criteria. Figure A.9 is a representation of the favorability of interconnection standards in each state based on NNEC criteria. Figure A.9 is consistent with Database of State Incentives for Renewable Energy (DSIRE) data and categorizes states with only guidelines for interconnection as "N/A," with the exception of two states, Montana and South Carolina. Montana is graded because all service providers have adopted the state guidelines, and South Carolina is included because of their adoption of investor-owned utility interconnection policies for residential solar systems.[57]

[57] NNEC 2011.

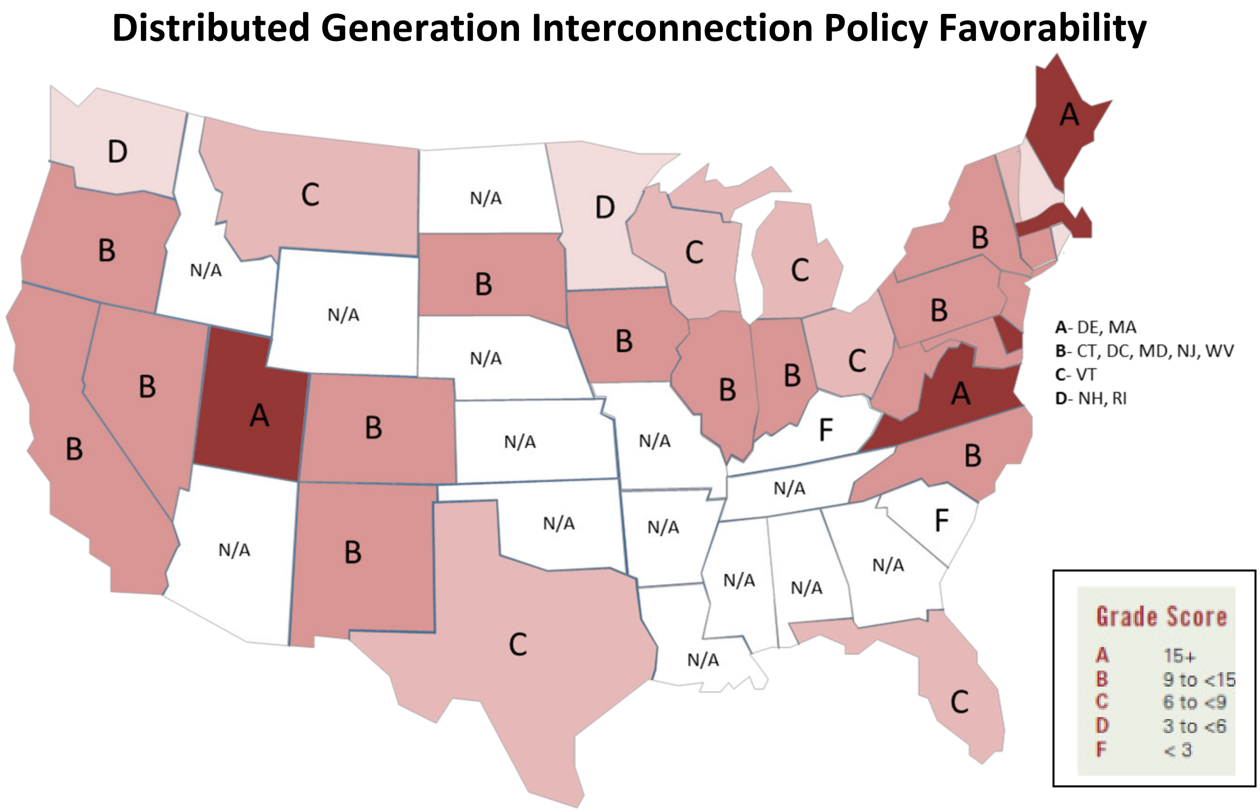



**Figure A.9**. Favorability of State Interconnection Standards for Grid Connection[58]

The NNEC study concluded that six states scored higher than 15 points (A) for all categories, indicating there are no barriers and best practices are in place. Seventeen states scored between 9 and 15 points (B), indicating they have good interconnection standards, but may still have barriers for certain customers to connect distributed resources to the grid. Seven states scored between 6 and 9 points (C), citing higher fees and long delays as barriers to their interconnection policies. Four states scored between 3 and 6 points (D); these states have cost and delay barriers, as well as many customers who are unable to connect their systems to the grid. Three states, Hawaii, Kentucky and South Carolina, received "F" grades because barriers are significant enough to inhibit most systems from connecting to the grid. Table A.6 summarizes the annual favorability grades since the study began in 2007.

[58] Adapted from NNEC 2011.

**Table A.6.** State Interconnection Grading Score Synopsis (2007-2011)[59]

| | Interconnection Grade | | | | | |
|---|---|---|---|---|---|---|
| Year | A | B | C | D | F | N/A |
| 2007 | 0 | 1 | 9 | 8 | 15 | 18 |
| 2008 | 0 | 11 | 3 | 9 | 14 | 14 |
| 2009 | 1 | 14 | 6 | 6 | 14 | 10 |
| 2010 | 4 | 16 | 7 | 4 | 5 | 16 |
| 2011 | 6 | 17 | 7 | 4 | 3 | 15 |

### A.3.3.1 Associated Stakeholders

Interconnection policy stakeholders include

- distribution-service providers and utilities, who will ultimately be responsible for managing the grid impact of these resources;
- manufacturers of DER products and services, who would benefit significantly from easier interconnection standards;
- regulators and policy makers, who are concerned with how electricity service providers choose to account for the costs of these resources, as well as other related legislation, such as meeting renewable-portfolio-standard requirements;
- end users who have distributed resources on their properties and want to tap into the potential benefits of selling power back to the grid;
- environmental organizations and other advocacy groups who promote renewable DER technologies to decrease greenhouse gas emissions or to promote energy independence.

### A.3.3.2 Regional Influences

Regional differences in perception of the costs and benefits associated with distributed resources have influenced where they are deployed. Many of the regional policies that have emerged are driven by state renewable portfolio standards or energy efficiency resource standards. Below are specific examples of regional DER interconnection policy influences:

- In contrast with many states, California has had a DER incentive program since 2001. In 2010, the Self-Generation Incentive Program installed over 1,300 dispersed generators, representing approximately 400 MW of capacity throughout the state.[60] In March 2012, a settlement of Rule 21 was filed, creating a "fast-track" process for interconnecting small DER systems and laying out a national best practices standard for grid interconnection.[61]

---

[59] NNEC 2011.
[60] Itron Inc. 2010. *Impacts of Distributed Generation: Final Report*. Prepared for the California Public Utilities Commission, Energy Division Staff. Accessed July 16, 2010 at http://www.cpuc.ca.gov/NR/rdonlyres/750FD78D-9E2B-4837-A81A-6146A994CD62/0/ImpactsofDistributedGenerationReport_2010.pdf (undated webpage).
[61] California Public Utilities Commission. 2012. *Rule 21*. Accessed May 30, 2012 at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/rule21.htm.

- In June 2011, Rhode Island approved interconnection standards for commercial and residential distributed generation systems. The law was enacted as an effort to promote expansion of small-scale, on-site renewable energy systems.[62]
- New York, which was one of the first states to adopt a standard interconnection policy in 1999, has continued to provide support for distributed generation. In 2010, the state streamlined the application process for systems of 25 kW or less, no longer requiring an application fee for grid interconnection. Residential systems supported include solar, micro-hydroelectric, CHP, fuel cell and wind systems.[63]
- Many states in the Southeast region have been resistant to implementing favorable standards for interconnection (see Figure A.9). Factors slowing penetration are similar to those associated with many energy efficiency standards, including historically low electricity rates, close proximity to the nation's fossil fuel production, and high energy demand lifestyles (energy consumption in the South is 43 percent of the U.S. total).[64]

### A.3.4 Challenges to Deployment

Barriers to DER interconnection will diminish as more states adopt progressive policies to allow higher penetration of DER. Barriers will remain in certain regions such as the Southeast, where adoption of interconnection standards has been slow.

#### A.3.4.1 Technical Challenges

There is still disagreement among some utilities and DER manufacturers about how to handle DER interconnection at high levels of penetration. With low levels of penetration, most utilities consider their distribution systems to be robust enough to handle disturbances in the system and unexpected DER disconnects. As the number of grid-connected DER systems grows, the back-feed of power to the grid could be significant enough to disrupt traditional transmission. Moreover, in order to employ the full potential of DER, states may need to revise and expand their existing laws or institute new ones that allow flow of surplus energy back to the grid.[65]

In addition, with more renewable sources of energy such as wind, solar panels and other photovoltaic generators being connected to the grid, utilities face intermittency issues due to inconsistency of these energy sources. Further, if climate protection legislation is passed, it may prove to be a barrier to more traditional forms of DER, such as diesel reciprocating engines.

#### A.3.4.2 Business and Financial Challenges

Service providers still have difficulty making the business case for integration of distributed resources, especially without integrated distribution and transmission planning. While using DER can

---

[62] Rhode Island Public Utilities Commission. 2011. "2011-H 6222, Chapter 26.3, Distributed Generation Interconnection." Providence, RI.
[63] New York State Public Service Commission. 2012. *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems*. Accessed May 30, 2012 at http://www.dps.ny.gov/Modified_SIR-Dec_2011-Final.pdf (revised April 1, 2012).
[64] Brown M, E Gumerman, X Sun, Y Baek, J Wang, R Cortes, and D Soumonni. 2010. *Energy Efficiency in the South*. Southeast Energy Efficiency Alliance, Atlanta, Georgia.
[65] NNEC 2011.

help providers reduce transmission congestion, these effects are difficult to model and are generally not within the purview of electricity service provider operations.

Business and financial challenges are also present on the demand side of the grid. Many state policies could provide enhanced financial incentives to consumers to promote DER installation. Productive interconnection standards could include renewable energy tax credits, public research and development funding and removal of regulatory burdens such as those associated with unfavorability of interconnection standards.

### A.3.5 Metric Recommendations

Future attempts at measuring this metric should give consideration to both defining what constitutes a standard DER interconnection policy and identifying surveys, reports, or other literature that will yield consistent results over a longer time horizon. In addition, consideration should be given to assessing the fairness of DER interconnection policies to encourage a level playing field for DER integrators, utilities, and ratepayers.

In addition, future measurements of this metric should include islanding and microgrids, which are beginning to represent a larger portion of distributed generation. Finally, the metric does not currently differentiate between non-renewable and renewable DER, which is a priority for many state energy efficiency policies. Future measurements could also distinguish between renewable energy systems and traditional fossil fuel generators that are grid-connected.

## A.4 Metric #4: Regulatory Recovery for Smart Grid Investments

### A.4.1 Introduction and Background

Section 1252 of the *Energy Policy Act of 2005* (EPAct 2005) outlines policies and objectives for encouraging smart grid development, including the provision of time-based rates to customers and the ability to send and receive real-time price signals. While EPAct outlined objectives for advancing smart grid concepts, it did not require electricity service provider investment in smart grid technologies, nor did it establish or outline a regulatory framework to encourage such investment.

The *Energy Independence and Security Act of 2007* as amended by ARRA, authorized programs designed to incentivize electricity company investments in the smart grid. Section 1306 authorized the Secretary of the U.S. Department of Energy to establish the Smart Grid Investment Grant (SGIG) Program, which was designed to provide reimbursement for up to 50 percent of a company's investment in smart grid technologies. Section 1306 also outlined what constituted qualified investments and defined a process for applying for reimbursement. Section 1304 authorized a smart grid regional demonstration initiative. Section 1307 encouraged states to require service operators to demonstrate consideration for smart grid investments prior to investing in non-advanced grid technologies. Section 1307 also encouraged states to consider regulatory requirements that included reimbursement of costs for any equipment rendered obsolete through smart grid investment.

In 2009, ARRA designated $4.5 billion in awards for all programs described under Title XIII (123 Stat. 138).[66] ARRA funded two major technology deployment initiatives: the SGIG and the Smart Grid Demonstration Program (SGDP). These programs are currently implementing 131 deployment and demonstration projects. An interim rate procedure has been adopted by the Federal Energy Regulatory Commission, allowing utilities to submit rate filings, including single-issue rate filings to recover smart grid investment costs.[67] However, state public utility commissions (PUCs) or other regulatory authorities make final decisions regarding retail utility rate recovery for smart grid investments.

To date, many states have implemented or are considering renewable energy and energy efficiency standards, which promote further investment and deployment of smart grid technologies. Smart grid investments often are capital intensive and include multiple jurisdictions within a provider's service area. A recent study concluded that net investment over the next 20 years necessary to implement a national smart grid amounts to between $338 and $476 billion, including an estimated $16 to $32 billion alone dedicated to AMI.[68] Although the up-front costs are significant, net benefits over the long term are estimated between $1,294 and $2,028 billion.[69] Even though net-benefit estimations are positive, service providers must be sure that regulatory recovery is feasible; while the up-front costs of the investment are

---

[66] DOE – U.S. Department of Energy. 2012. *Successes of the Recovery Act—January 2012*. Washington D.C. Accessed July 10, 2012 at http://energy.gov/downloads/successes-recovery-act-january-2012 (undated webpage).

[67] 18 CFR Chapter I. 2009. "Smart Grid Policy." *Code of Federal Regulations*. Federal Energy Regulatory Commission. Accessed October 21, 2010 at http://www.ferc.gov/whats-new/comm-meet/2009/031909/E-22.pdf (undated webpage).

[68] EPRI – Electrical Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed May 16, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.

[69] EPRI 2011.

easy to calculate, the back-end benefits can still be difficult to monetize within current regulatory valuation models.

### A.4.2 Description of Metric and Measurable Elements

*(Metric 4) the weighted average (respondents' input weighted based on total customer share) percentage of smart grid investment recovered through rates.*

### A.4.3 Deployment Trends and Projections

The smart grid interviews conducted for this report included 30 electric service providers. Respondents were asked the following question: What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place to support smart grid investment. Respondents' answers to this question are summarized below.

- Twelve companies (40.0 percent) indicated that there were no regulatory policies in place to support smart grid investment, as compared to 54.2 percent in 2010.
- Five companies (16.7 percent) indicated there were mandates in place to support investment in smart grid features, as compared to 12.5 percent in 2010.
- Seven companies (23.3 percent) indicated there were incentives in place to encourage smart grid investment, as compared to 25 percent in 2010.
- Sixteen companies (53.3 percent) indicated that there was some form of regulatory recovery for their smart grid investments, as compared to 33.3 in 2010.

Companies were also asked to estimate the percentage of smart grid investments to date that has been recovered through rates, and compare that total against their expectations for future investments in the smart grid. The electricity service providers interviewed for this report indicated that, on average (weighted), they are recovering 59.8 percent of their investment through rate structures, compared to 23.5 percent in the 2010 SGSR and 8.1 percent estimated for the 2009 SGSR. The respondents further predicted regulatory recovery rates will expand in the future, ultimately reaching 94.9 percent. The predicted recovery rates far exceed the 37.3 percent estimated by electricity service providers in 2010. Finally, 25 electricity service providers (83.3 percent) reported they had made smart grid investments, one respondent (3.3 percent) reported no smart grid investment, and four providers (13.3 percent) did not respond to the question. When asked if they expected to make future smart grid investments, 28 (93.3 percent) electricity service providers indicated they did.

While state regulations for cost recovery of AMI and smart grid investments are still emerging, some service providers are utilizing a decoupling mechanism, which is a rate adjustment that ensures an electricity service provider will recover the fixed costs approved by their regulatory commission, including an approved return on investment, regardless of sales volume. Types of decoupling include:

- full decoupling – An electricity service provider recovers the allowed revenue, no matter the reason, for the difference in projected versus actual sales.
- partial decoupling – An electricity service provider recovers some of the difference between the allowed and actual revenue.

- limited decoupling – An electricity service provider recovers a true-up cost only when actual revenue deviates from allowed revenue for a specific reason.[70]

Other forms of regulatory recovery for smart grid investments include lost revenue adjustment mechanisms (LRAMs)—riders and trackers that impose rate adjustments based on estimates of lost revenue from energy efficiency or demand-side management programs. When states decouple and/or impose LRAMs, the link between sales and revenue weakens, allowing utilities to recover fixed costs even though electricity demand may be decreasing because of energy efficiency programs.

As shown in Figure A.10, 13 states including the District of Columbia currently have a revenue decoupling mechanism in place, 9 states have pending policies, and nine states have LRAMs, including Utah and Arkansas, which have standards pending. Since the 2010 SGSR was published, decoupling policies were enacted in Arkansas, Rhode Island, and Montana.[71]

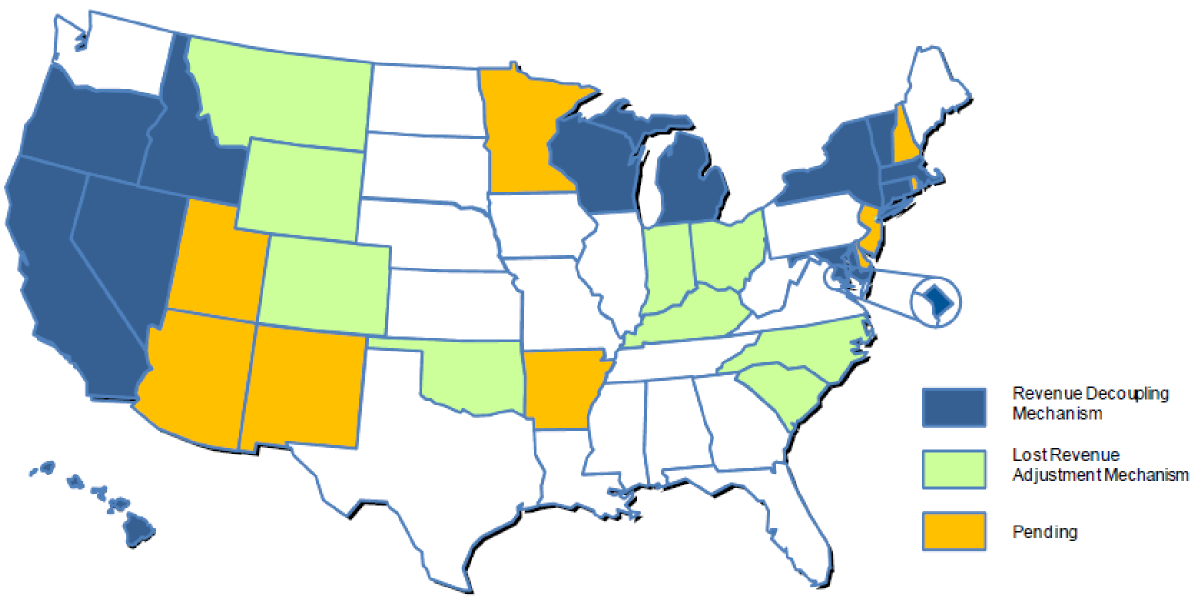



**Figure A.10**. Status of States with Decoupling or Lost Revenue Adjustment Mechanisms[72]

In addition to lost-margin recovery, increased use of state energy-savings goals, such as renewable energy efficiency portfolio standards, have also influenced state regulatory commissions to expand financial incentives to electricity service providers that invest in energy saving mechanisms, such as energy efficiency programs that may leverage smart grid technologies.

Figure A.11 presents states that have performance incentives for investor-owned utilities. Performance incentives are policies that promote energy reduction programs by awarding service providers and shareholders when a specified target level of energy efficiency is reached, thus promoting

[70] NREL – National Renewable Energy Laboratory. 2009. *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities.* Golden, Colorado. Accessed July 20, 2010 at http://www.nrel.gov/docs/fy10osti/46606.pdf (undated webpage).
[71] IEE – Institute for Electric Efficiency. 2011. *State Energy Efficiency Regulatory Frameworks*. Washington, D.C. Accessed April 22, 2012 at http://www.edisonfoundation.net/IEE/Documents/IEE_StateRegulatoryFrame_0611.pdf (undated webpage).
[72] IEE 2011.

statewide energy efficiency programs and smart grid technology deployment. Since the 2010 SGSR was published, performance incentive programs were expanded or introduced in Arkansas, Florida, Indiana and New York.

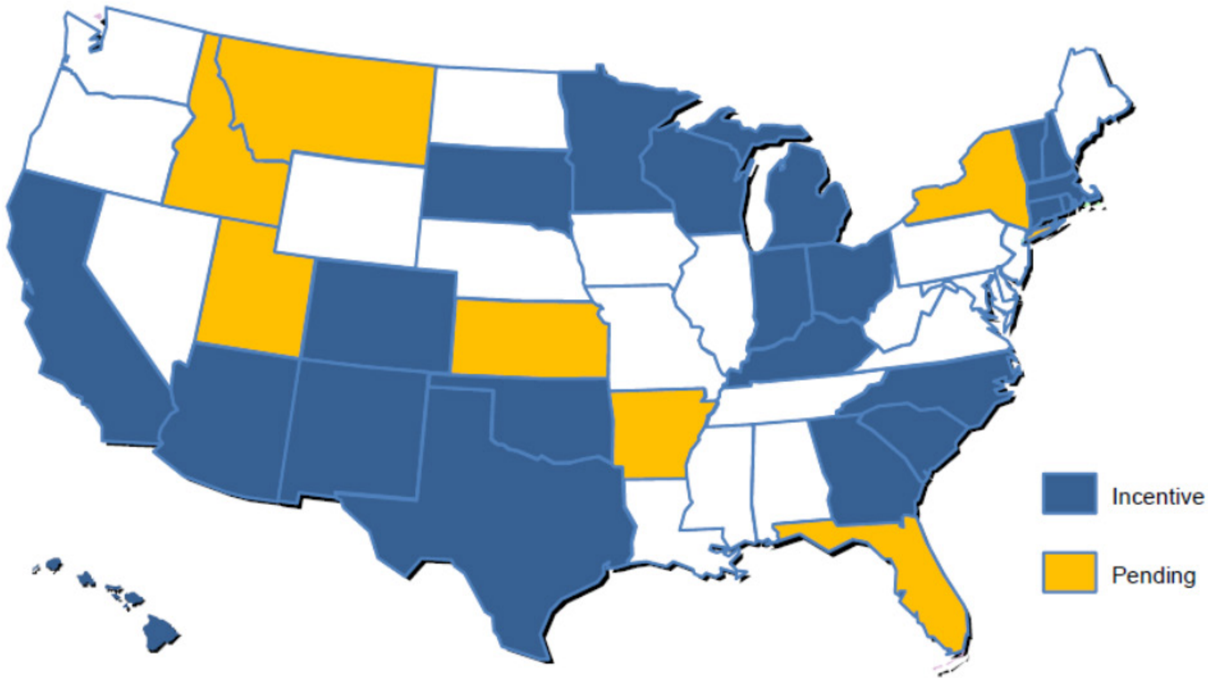



**Figure A.11**. Improved-Performance Incentive Programs[73]

### A.4.3.1 Associated Stakeholders

Stakeholders with an interest in regulatory recovery for smart grid investments include:

- regulatory agencies considering smart grid business cases
- residential, commercial, and industrial customers who could benefit from the deployment of smart grid technologies
- consumer advocacy groups monitoring the impact of pricing tariffs on end users
- transmission and distribution service providers and balancing authorities interested in reducing peak demand, enhancing efficiency, and reducing the costs of supplying energy
- policy advocates, such as environmental organizations, interested in reducing the need for new power-generation plants
- policy makers interested in fostering competitive markets and managing load while reducing the need to expand existing generation, transmission, and distribution infrastructure.

[73] IEE 2011.

### A.4.3.2 Regional Influences

Traditionally, utilities seeking regulatory recovery for investments, including decoupling proposals, must do so by submitting a request to the state PUC for review. Examples of states that have recently submitted such requests include:

- On July 1, 2010, Georgia Power submitted a request to the Georgia Public Service Commission requesting an 8.2 percent, or $615 million, rate increase to recover capital costs of deploying smart grid technology and clean generation.[74] The request was approved, and Georgia Power raised rates by 10 percent in 2011, 2.6 percent in 2012, and will increase by an additional 1.2 percent in 2013.[75]
- In 2009, the Illinois Commerce Commission approved a rate increase of $70.7 million for a Commonwealth Edison AMI pilot program. However, in May, 2011, the Commission rejected a rate adjustment of $9 million for continued smart grid deployment, research and development.[76]
- In 2011, the Texas State Legislature overhauled the electric industry in an effort to improve utility rulemaking policies, system reliability and environmental oversight. Senate Bill 1693 approves the creation of a framework allowing service providers to recover capital investments relating to consumer-owned distributed generation systems, such as electric vehicle infrastructure.[77]
- The Hawaii PUC approved decoupling policies for all utilities initially in 2010, and continues to allow rate adjustments in the state. In 2011, the PUC allowed general rate adjustments that allow Hawaiian Electric to recover $5.8 million in AMI investments through general rate decoupling.[78]
- In 2011, Central Maine Power was mandated to offer an opt-out policy for customers not wanting to have AMI installed at their homes. The PUC allowed rate recovery for AMI deployment, but only from customers who agreed to have AMI installed at their homes.[79]

While decoupling, LRAM, and incentive programs have proved to be important factors for regulatory recovery of smart grid investments, there have been some programs that failed to gain stakeholder support. For example, in 2011, Commonwealth Edison's proposal to recover distribution automation and other smart grid programs was rejected.[80] Similarly, in May, 2010, the Public Service Commission of Maryland rejected regulatory recovery for an $835 million proposal by Baltimore Gas and Electric (BGE) to install AMI meters at all customer homes and institute time-of-use pricing tariffs.[81] Finally, an appeals

---

[74] Georgia Power. July 1, 2010. *Georgia Power Seeks Cost Recovery of Investments in Cleaner Generation, Smart Grid and Environmental Controls*. Press Release, Atlanta, Georgia. Accessed August 6, 2010 at http://www.smartgridnews.com/artman/uploads/1/Georgia_Power_Seeks_Cost_Recovery_of_Investments_in_Cleaner_Generation.pdf (last updated July 1, 2010).
[75] Georgia Power. 2012. *Learn More about Georgia Power's Pricing and Rates. Get the Facts*. Atlanta, Georgia. Accessed May 16, 2012 at http://www.georgiapower.com/pricing/residential/get-the-facts.cshtml (undated webpage).
[76] IEE 2011.
[77] AECT – Association of Electric Companies of Texas. 2011. *82nd Texas Legislature: New Changes in the Texas Electric Industry*. Accessed June 19, 2012 at http://aectnet.wordpress.com/2011/06/09/82nd-texas-legislature-new-changes-in-the-texas-electric-industry/.
[78] IEE 2011.
[79] IEE 2011.
[80] IEE 2011.
[81] Nazarian DRM, HD Williams, S Brogan, L Brenner, and TM Goldsmith. June 21, 2010. *Order No. 83410: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*. Case No. 9208, Public Service Commission of Maryland.

court in the state of Michigan overturned a PUC-approved rate recovery program that sought to recover $37 million through rate adjustments to help Detroit Edison pay for smart meter installation.[82]

### A.4.4 Challenges to Deployment

A number of technical and business/financial barriers exist due to a lack of regulatory recovery of smart grid investments as outlined below.

#### A.4.4.1 Technical Challenges

Technical barriers include:

- When making the case to utility regulatory commissions, technical barriers may exist due to the unproven nature of some smart grid technologies. Commissions may need assurance that specific equipment such as meters will not be obsolete in a few years as smart grid technology advances.
- Smart-grid-related projects vary by electric service provider in terms of functionality, requirements, and implementation approaches. General agreement is needed on the points in these systems at which interfaces can be defined and stabilized. Such standards are being composed by the National Institute of Standards and Technology, but are still in development stages.

#### A.4.4.2 Business and Financial Challenges

Business and financial barriers include the following:

- Deploying new smart grid technologies poses significant costs to service providers. Regulatory recovery of these costs can be difficult to justify, which creates a disincentive to technology deployment.
- It may be difficult to demonstrate positive net benefits, causing consumers and utility commissions and/or other regulatory bodies to oppose regulatory recovery for smart grid investments.
- Current research suggests that performance-based regulation and dynamic pricing adjustments may be viable options to ensure high quality electric service provider investments.[83]
- Due to the up-front costs involved, many service providers seek cost recovery for pilot programs or before smart grid technologies are deployed. However, some regulatory utility commissions are not authorizing rate increases for smart grid deployment.
- For operators providing service in multiple jurisdictions, the regulatory requirements in one area may not be consistent with those in another.
- Until the value proposition can be demonstrated to retail customers, the responsiveness of end users will be limited and thus limit the cost recovery potential of both aggregators and service providers. That is, consumers need to experience cost savings in order to support smart grid deployment. If

[82] Smart Grid Today. 2012. *Court Rejects Michigan PSC's Decisions on Cost Recovery, Decoupling*. Published April 16, 2012 at http://www.smartgridtoday.com/public/3920print.cfm (undated webpage).

[83] MIT – Massachusetts Institute of Technology. 2011. *The Future of the Electric Grid: An Interdisciplinary MIT Study*. Cambridge, Massachusetts. Accessed March 17, 2012 at http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf.

smart grid devices cost more than the offsetting value of reduced energy consumption or if the savings are not well defined or understood, consumers may be unwilling to invest in them. Without an expectation of buy-in from consumers, innovators and service providers may also be reluctant to invest in smart grid technologies.

### A.4.5 Metric Recommendations

More information regarding percentage of smart grid investments recovered through rate adjustments is required to accurately measure this metric. Information regarding specific electricity service provider participation in capital recovery programs was not found. Consideration should also be given to modifying this metric to focus more on decoupling programs, which are often used to help utilities recover costs where shortfalls in revenue would result from the implementation of energy efficiency programs.

Education programs need to be developed that document the costs and benefits of smart grid programs and the associated laws and regulations that need to be developed to provide for the recovery of smart grid investments.

## A.5 Metric #5: Load Participation

### A.5.1 Introduction and Background

This metric measures the fraction of load served by interruptible tariffs, direct load control (DLC), and consumer load control. Not only are these properties critical for enabling measurement and modeling of a smart grid's load participation, but they also provide a good measure of the grid's current capability to respond to changing load and generation conditions across the grid.

Demand response is defined according to the U.S. Department of Energy in its February 2011 report to Congress as follows:

*"Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."*[84]

Demand response is typically seen, from the point of view of the electricity grid, as a form of additional capacity and is discussed in terms of megawatts (MW). Demand-response programs have seen highly variable levels of interest over the years. The EIA reports that spending for demand-side management, one of the earlier forms of demand response (albeit focused primarily on energy efficiency measures with associated peak-load benefits), rose to $2.74 billion in 1994 before declining to a low of $1.3 billion in 2003.[85] The latest data indicates that investment had reached a new high of $4.2 billion in 2010 (nominal dollars).[86]

Figure A.12 graphs historic and projected levels of electricity sales by sectors. The sectors showing the greatest levels of forecasted growth (the commercial and residential buildings sectors) are those where future load participation investment is likely to have the greatest impact. Historically, residential and commercial energy sales have been lower than or close to industrial levels, but projections for these sectors show a marked departure from this trend with commercial and residential sales continuing to rise while predicted industrial consumption will remain essentially flat during the same period. Even when considering projected growth and the key role that demand response is likely to play in the smart charging of electric vehicles, when compared to the other sectors transportation will be a relatively insignificant portion of the market for some time to come.[87]

[84] FERC – Federal Energy Regulatory Commission. February 2011. *2010 Assessment of Demand Response and Advanced Metering*. Staff Report, Docket Number AD-06-2-000, Washington, D.C. Accessed June 13, 2012 at https://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf (undated webpage).

[85] EIA – U.S. Energy Information Administration. October 2011a. *Annual Energy Review 2010*. DOE/EIA-0384(2010), Office of Energy Statistics, Washington, D.C. Accessed June 2011 at http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

[86] EIA – U.S. Energy Information Administration. November 2011b. "Table 9.7: Demand-Side Management Program Direct and Indirect Costs, 1999 through 2010." In *Electric Power Annual 2011,* Washington, D.C. Accessed June 2011 at http://www.eia.gov/electricity/annual/pdf/table9.7.pdf.

[87] EIA – U.S. Energy Information Administration. 2012. "Electricity Supply, Disposition, Prices, and Emissions, Reference Case." *Annual Energy Outlook 2012 Early Release*. Washington D.C. Accessed June 13, 1012 at http://www.eia.gov/oiaf/aeo/tablebrowser/#release=EARLY2012&subject=0-EARLY2012&table=8-EARLY2012&region=0-0&cases=early2012-d121011b.

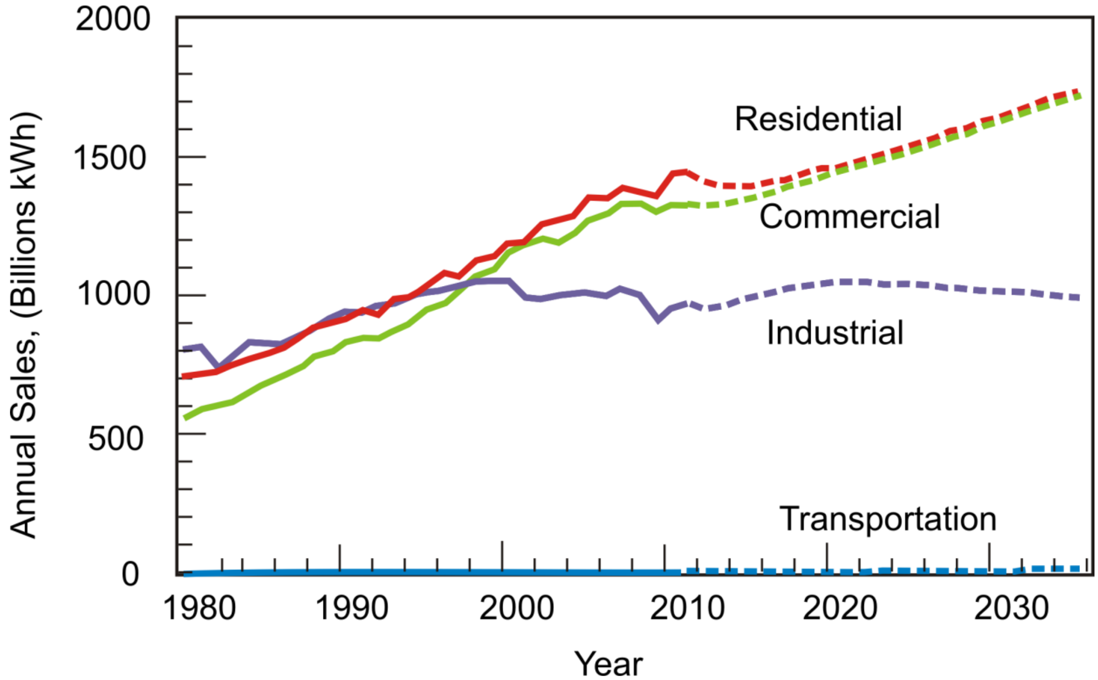



**Figure A.12**. Annual Electricity Sales by Sector, 1980 to 2035 (billion kWh)[88,89]

According to a 2011 survey by the FERC, about 7.5 percent of non-coincident summer peak customer demand (or 5.5 percent of peak summer capacity) is served through a time-based rate or enrolled in some form of demand response program.[90,91] The latest EIA data shows 16.8 million smart meters installed in 2011.[92] The 2010 FERC survey shows 12.8 million smart meters installed nationwide by the end of 2009, representing 8.7 percent of all U.S. electric meters.[93] The Institute for Electric Efficiency estimated a nationwide total of 26.7 million in 2011, and 36 million by May, 2012, representing 18 and 24 percent of U.S. electric meters, respectively. In general, the number of entities offering demand response and load-management programs is small, with past FERC reports indicating heavy weighting on DLC and interruptible/curtailable tariffs. This distribution between different program types is set to remain dominated by DLC and interruptible/curtailable tariffs into the near future, though utilities responding to the 2010 FERC assessment indicate that there will be stronger growth in DLC programs (see Table A.7).[94]

[88] EIA 2012.
[89] EIA 2011a.
[90] FERC 2011.
[91] NERC – North American Electric Reliability Corporation. 2011. *2011 Reports (with 2010 Actuals)*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/page.php?cid=4|38|41 (undated webpage).
[92] EIA – U.S. Energy Information Administration. November 2011c. "Net Metering and Green Pricing: Advanced Metering - Number of Meters by Type and Megawatthours Served, by State by Sector" found at *Electricity: Data*. Accessed May 30, 2012 at http://205.254.135.7/electricity/data.cfm#sales (last updated November 9, 2011).
[93] FERC 2011.
[94] FERC 2011.

**Table A.7**. Number of New Demand Response and Time-Based Rate/Tariff Programs Expected in the Near Term [95]

| | CY10[a] | CY11 - CY12 | CY13 - CY15 |
|---|---|---|---|
| Direct Load Control | 253 | 324 | 563 |
| Interruptible Load | 122 | 119 | 121 |
| Critical Peak Pricing with Controls | 13 | 19 | 22 |
| Load as Capacity Resource | 36 | 22 | 22 |
| Spinning Reserves | 10 | 11 | 10 |
| Non-Spinning Reserves | 5 | 8 | 11 |
| Emergency Demand Response | 53 | 46 | 33 |
| Regulation Service | 3 | 5 | 6 |
| Demand Bidding and Buyback | 4 | 6 | 5 |
| Time-of-Use Pricing | 219 | 205 | 193 |
| Critical Peak Pricing | 42 | 62 | 66 |
| Real-Time Pricing | 24 | 30 | 29 |
| Peak Time Rebate | 13 | 27 | 27 |
| System Peak Response Transmission Tariff | 3 | 4 | 3 |
| Other | 35 | 27 | 25 |

[(a)]CY = calendar year

In a 2008 Notice of Final Rulemaking issued by FERC[96] regarding wholesale competition, the following four new incentive-based demand response proposals were adopted:

- Allow demand response resources to provide services such as supplemental reserves and to correct generator imbalances in regional transmission organization (RTO)/ISO markets when they meet the technical requirements.
- During emergencies, eliminate excess charges when using less energy than was purchased in the day-ahead market.
- Allow an organization that aggregates demand response to bid into organized markets on behalf of their retail customers.
- Include provisions that allow market power rules to be modified when demand is approaching available supply.

As with many of the other smart grid metrics covered in this document, demand response received a significant boost from the *American Recovery and Reinvestment Act (ARRA) of 2009*. The interdependence of the smart grid makes it difficult to easily categorize investment as being for a specific

[95] FERC 2011.
[96] 18 CFR 35. 2008. "Wholesale Competition in Regions with Organized Electric Markets. Final Rule." *Code of Federal Regulations*, Federal Energy Regulatory Commission. Accessed May 30, 2012 at http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf (undated webpage).

purpose, such as demand response, because often a single investment can facilitate multiple aspects of smart grid impact. .[97]

### A.5.2 Description of Metric and Measurable Elements

The following metric identifies the most important factor in understanding and quantifying managed load:

*(Metric 5) Fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives—the load reduction as a percentage of net summer capacity.*

### A.5.3 Deployment Trends and Projections

Many organizations, such as the Electric Reliability Council of Texas, the Public Utility Commission of Texas, and the California and New York ISOs act to balance and curtail loads for reliability purposes. Nationally, demand response participation is very low. Figure A.13 illustrates that load management was 1.21 percent of net summer capacity in 2010, up from a low of 0.96 percent in 2004.[98,99] Net summer capacity only includes utility scale generators and does not include a demand response component. As such, the metric provides only an indication of the scale of peak load reduction. Though the most recent year for which data is available (2010) shows a new high in total load under management, Figure A.13 and Figure A.14 indicate an overall reduction relative impact of demand management over much of the previous decade.

---

[97] DOE – U.S. Department of Energy. November 2011. *Recovery Act Selections for Smart Grid Investment Grant Awards – By Category*. Accessed June 13 2012 at http://energy.gov/sites/prod/files/SGIG Awards by Category 2011 11 15.pdf (undated webpage).

[98] EIA – U.S. Energy Information Administration. October 2012f. "Table 8.11a: Electric Net Summer Capacity: Total (All Sectors), 1949-2011." In *Annual Energy Review 2011*. DOE/EIA-0384(2011), Washington, D.C. Accessed October 17, 2013 at http://www.eia.gov/totalenergy/data/annual/archive/038411.pdf (last updated September 2012)..

[99] EIA – U.S. Energy Information Administration. November 2013a. "Table 10.1: Demand-Side Management Actual Peak Load Reductions by Program Category." In *Electric Power Annual 2011 Data Tables*, Washington, D.C. Accessed October 17, 2013 at http://205.254.135.7/electricity/annual/.

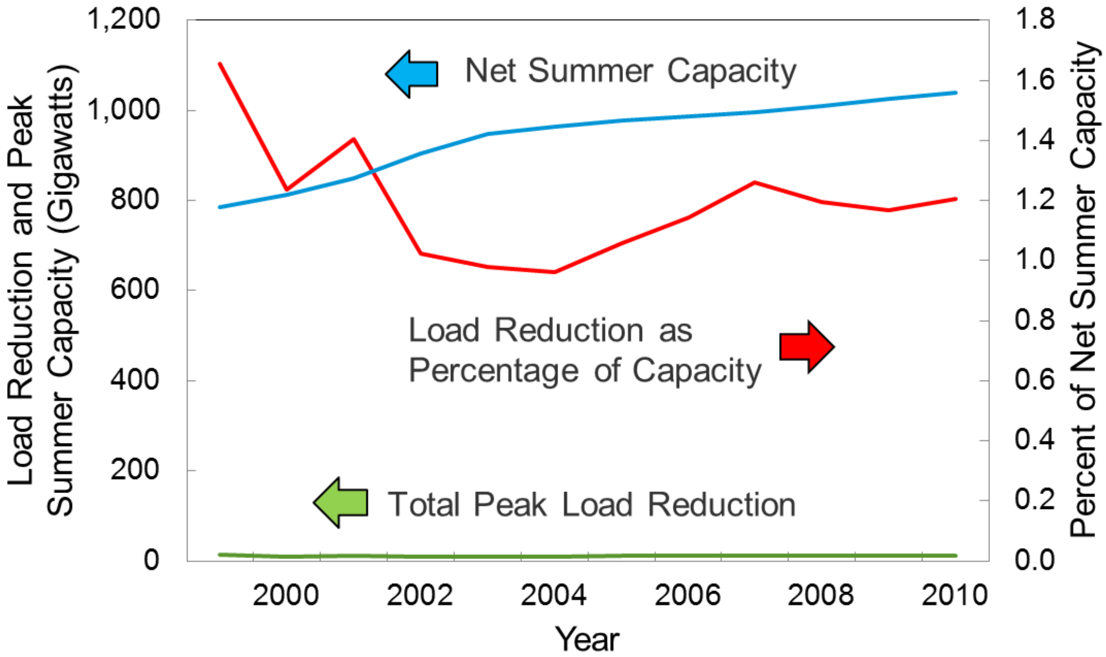



**Figure A.13**. Historic Load-Management Peak Reduction as a Percentage of Net Summer Capacity[100,101]

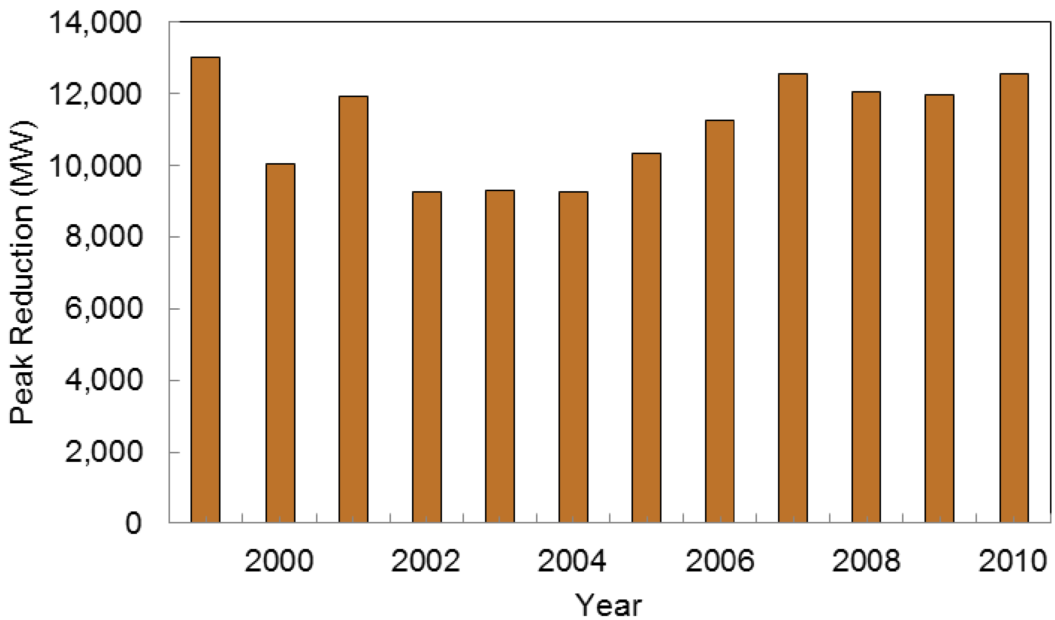



**Figure A.14**. National Historic Demand Response and Load-Management Peak Reduction[102]

[100] EIA 2012f.
[101] EIA 2013a.
[102] EIA – U.S. Energy Information Administration. November 2013a. "Table 10.1: Demand-Side Management Actual Peak Load Reductions by Program Category." In *Electric Power Annual 2011 Data Tables*, Washington, D.C. Accessed October 17, 2013 at http://205.254.135.7/electricity/annual/.

The trend has been somewhat volatile over the past decade, and especially over the last few years, making it difficult to predict future trends. Respondents to FERC's 2010 survey reported having available 10,977 MW of interruptible load (up from 8,032 MW in 2008) and 9,006 MW (down from 11,045 MW in 2008) of direct load control.[103] This decrease may reflect a change in how the survey was performed rather than an actual drop in DLC.[104] This latest survey indicates that approximately 2 percent of net summer capacity is under DLC or interruptible tariffs. That this value differs from the actual peak MW reduction provided by EIA could indicate an uneven distribution of such programs across utilities and a poor match between the capability and the need for peak load reduction.

In a 2009 report, the Electric Power Research Institute (EPRI) predicted by 2030 a "realistically achievable potential" summer peak reduction due to demand response of 7 percent and a "maximum achievable potential" of 9.1 percent.[105] The 2009 FERC Assessment study projects that the effects of demand response programs under its business-as-usual case would reduce peak demand by as much as 38 gigawatts (GW) by 2019, a 4 percent reduction, or as much as 82 GW, a 9 percent reduction, from peak demand if today's best practices were instituted across the market.[106]

#### A.5.3.1 Associated Stakeholders

Stakeholders include the following:

- end-users (consumers) – residential, commercial, industrial; as the number and variety of demand response programs available expands, the potential for utility customers to capitalize on existing behavior or consumption flexibility will increase
- electric-service retailers – regulated and unregulated electricity providers, who provide energy services, market incentives and supply
- demand response aggregators – who coordinate end-users into a pool of load reduction potential
- local, state, and federal energy policy makers – who will need to evaluate the effects of current regulations on demand response, as well as understand how demand response fits into current targets for grid capability, reliability and efficiency
- transmission providers – who provide and/or recognize response programs for transmission of electricity. Being removed from the end-user where the load can be controlled
- distribution providers – who will provide incentive programs to encourage demand response and will be responsible for designing programs to have the greatest impact and appropriately reward end-users
- generation and demand wholesale-electricity traders/brokers – who manage the generation required to meet load net of demand response
- product and service providers – who provide the communication technologies and responsive end-use products that will provide and react to the supply and demand information available to providers, transmitters, and end-users.

[103] FERC 2011.
[104] Please see the FERC report for more information on the survey methodology change.
[105] EPRI – Electric Power Research Institute. January 2009. *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* (2010–2030). Palo Alto, California. Accessed June 13, 2012 at http://www.edisonfoundation.net/IEE/Documents/EPRI_AssessmentAchievableEEPotential0109.pdf.
[106] FERC 2011.

### A.5.3.2 Regional Influences

Demand response levels vary significantly by region of the NERC. This variation stems from a number of sources, including differential load growth rates, the local costs of additional capacity, the regional regulatory environment,[107] and local technical issues. Load growth rate and the cost of additional capacity influence the economics of load participation. A growth rate that outstrips a utility's ability to add additional generating capacity or a high cost of additional capacity incentivizes utilities to offer more generous compensation for load participation. Regional regulations may make it difficult for utilities to alter pricing structures in a way that provides adequate incentive for end-users to adopt load participation. Regional differences may also create technical difficulties for analysis, requiring aggregation of regional data to the state and national level. For example, differences in the frequencies of load and demand measurements (seconds, minutes, hours, days) may introduce interpolation or extrapolation errors. This could be especially true for regions that find it difficult or expensive to monitor and/or communicate such data, such as sparsely populated rural areas with poor wireless-communication coverage. Regional differences influence not only the total load participation in different areas but also the distribution of methods employed. Direct load control as a portion of total summer peak is much higher in the FRCC (~5.5 percent) than in other areas (see Figure A.15) while in the MRO, interruptible demand is much higher (4.0 percent of internal demand) than in other regions (1.6 percent of internal demand).

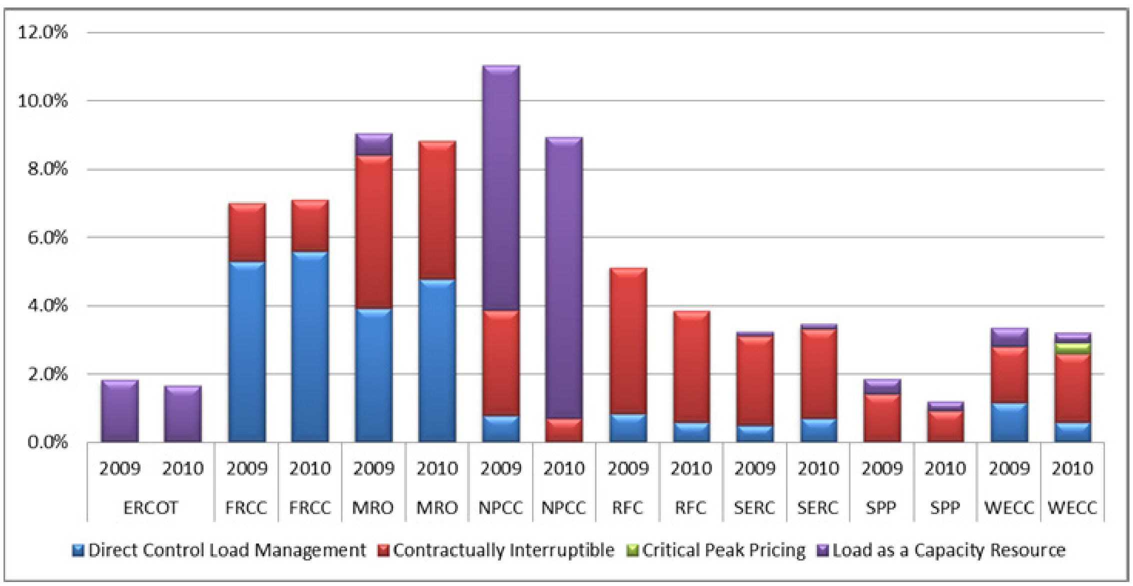



**Figure A.15**. Demand Response by NERC Region for 2009 and 2010[108,109,110]

[107] FERC – Federal Energy Regulatory Commission. June 2010. *National Action Plan on Demand Response.* Staff Report, Docket No. AD09-10, Washington, D.C. Accessed June 13, 2012 at http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf.

[108] NERC – North American Electric Reliability Corporation. May 2010. *2010 Summer Reliability Assessment*. Princeton, New Jersey. Accessed June 13, 2012 at http://www.nerc.com/files/2010%20Summer%20Reliability%20Assessment.pdf.

[109] EIA – U.S. Energy Information Administration. December 2010. "Monthly Peak Hour Demand, by North American Electric Reliability Corporation Assessment Area." *EIA Form 411*. Washington, D.C. Accessed June 13 1012 at http://www.eia.gov/cneaf/electricity/page/eia411/eia411.html.

[110] NPCC = Northeast Power Coordinating Council; RFC = ReliabiltyFirst Corporation; SERC = SERC Reliability Corporation; SPP = Southwest Power Pool; WECC = Western Electricity Coordinating Council.

### A.5.4 Challenges to Deployment

The technical, business and financial, and policy challenges to demand participation follow. Technical challenges to load participation remain in the area of acquisition, communication and storage of data, while the business challenges lie mainly in the area of acquisition of load participation software and equipment. Policy challenges sometimes occur because demand aggregators may be blocked from demand participation.

#### A.5.4.1 Technical Challenges

The remaining technical challenges to demand response lie mainly with the acquisition, communication, and storage of data. Timely and secure access to meter data and communication infrastructure is vital to supplying the energy market with the data necessary to track energy prices, estimate and execute demand response measures, and provide consumers and suppliers with accurate, real-time data.[111]

In addition to data availability, considerable data infrastructure improvements will be required to collect the data and support the necessary data accessibility.[112] The smart metering and data collection required for operating a functional demand response program will require that extensive volumes of data be sent back to the electricity service provider at regular intervals. Data from smart meter readings on 15-minute intervals require approximately 400 megabytes (MB) of data storage per smart meter annually, or 200 terabytes per year for 500,000 meters (including data redundancy for disaster recovery).[113] Nationally, at a rate of 400 MB per year (using 15-minute intervals), if every electricity customer had an advanced meter, the data needs of the smart grid would be 57.3 petabytes ($57.3*10^{15}$) of data storage per year.

Additional technical considerations include standardization of metering and/or appliance timers and communication equipment, i.e., "plug and play," and methods for communicating data from household meter to electricity service provider. Adoption of a common standard for communication between demand response equipment is seen as an important step to the widespread adoption of demand response. Open Automated Demand Response (OpenADR) may be one such communication approach that allows significant amounts of automated demand response to occur.[114] Demand response programs need to address the lack of electricity service provider signals that reflect consumer needs. Further technical issues could include incorporation of local and regional objectives that could be addressed only through customization of demand response programs. Another technical issue could be the use of installed equipment for persistent control rather than for emergency curtailment. Demand response programs will

---

[111] FERC 2010.

[112] Miller J. April 2009. "The Smart Grid – Some Technical Challenges." Presented at the *Symposium on Modeling & Control of Alternative Energy Systems*, April 2, 2009, p. 35, U.S. Department of Energy, Washington, D.C. Accessed June 11, 2012 at http://www.smartgridinformation.info/pdf/1414_doc_1.pdf.

[113] Pariseau B. May 1, 2009. "Energy IT Sees Smart-Grid Boon for Data Storage." *SearchStorageChannel.com*. Accessed June 11, 2012 at http://searchstoragechannel.techtarget.com/news/article/0,289142,sid98_gci1355355_mem1,00.html.

[114] Rosenthal J and D Wylie. ca. June 2012. *Automated Demand Response Shows Smart Grid Power in Volatile Energy Environment*. Accessed June 20 2012 at http://www.elp.com/index/display/article-display/2301558781/articles/utility-automation-engineering-td/volume-17/issue-6/features/automated-demand-response-shows-smart-grid-power-in-volatile-energy-environment.html (undated webpage).

also need to be able to regulate loads up or down to accommodate intermittent renewable resources.[115] In addition, development of more spinning reserves and localized dispatch for distribution capacity management are needed to accommodate increasing levels of demand response. Finally, resolving all of these issues will not allow for maximum benefit without simultaneously developing some way for generation entities to incorporate all of the disparate demand response opportunities into a framework that fits into their existing management and dispatch strategies.

#### A.5.4.2 Business and Financial Challenges

The expense of increasing load participation comes from both the supply and demand sides of the market. Companies may need to invest in new load-management programs and/or refine current SCADA techniques. Further costs of developing and installing hundreds of thousands to millions of units of load-management and demand response equipment, be that some form of advanced metering or otherwise, represent large investments of capital that must be raised and recovered, and may pose a significant challenge to electricity service provider companies.[116] This is especially true without a system to handle higher-than-expected costs such as those that stem from advanced meter opt-out rules (decreasing the base over which costs can be spread and benefits accrued) and other unexpected cost overruns.[117]

On the demand side, customers need to be educated about the potential savings (or earnings) from their participation. Additionally, they will need simple, user-friendly enabling technologies that inform them of grid events (electricity price changes, shortages, etc.) and allow them to operate their electrical loads in accordance with these events. A further hindrance on the demand side is the lack of customers on time of use (TOU) rates. Especially in the residential sector, adoption of TOU rates has been low. TOU rates can help customers make appropriate economic decisions as well as foster new technology and program developments.[118]

Many of the barriers to load participation that remain are business challenges related to policy and regulation. Due to the critical nature of the energy distribution system, any changes to how capacity is calculated and priced often must overcome regulatory hurdles. This remains an issue for third-party demand response aggregators who are sometimes blocked from practicing in certain state or other local jurisdictions. Regulatory constraints on how energy is priced also reduce the scope for cost recovery and the adoption of TOU rates, for both of which the constraints are significant hurdles to demand response.[119]

### A.5.5 Metric Recommendations

More information from the EIA on the content of their load-management variable would be useful. EIA's Form 861 survey, *Annual Electric Power Industry Report*, does not provide a clear definition of what is measured as load participation. In addition, more information on the impact by category of

[115] Callahan SJ. 2007. "Smarter Meters Require Open Standards." *Electric Light and Power*. Accessed June 11, 2012 at http://www.elp.com/index/display/article-display/284514/articles/electric-light-power/volume-85/issue-1/sections/news-analysis/smarter-meters-require-open-standards.html (undated webpage).
[116] Steklac I. 2007. "AMI: Bridging the Gaps." *Power & Energy*, Accessed June 11, 2012 at http://www.nextgenpe.com/currentissue/article.asp?art=271002&issue=215 (undated webpage).
[117] FERC 2011.
[118] FERC 2011.
[119] FERC 2011.

response expanded to the total population in FERC's demand response report could provide further insights into the amount of load that is actually being captured.

In addition, Metric 5 could be improved on two fronts. First, the metric should be broken into two parts, one quantifying the amount of load served by tariffs that support load participation and the second showing how much actual impact load participation has on the annual peak demand. It may also help improve the usefulness of Metric 5 to better understand how the impacts of different types of load participation are calculated; for example, is a load served through an interruptible tariff considered equal to one served by a TOU tariff? Disaggregating the key elements of this metric and having available details regarding how the data was developed would both greatly improve the understanding and usefulness of an already important metric.

## A.6 Metric #6: Load Served by Microgrids

### A.6.1 Introduction and Background

Microgrids may change the landscape of electricity production and transmission in the United States due to changing technological, regulatory, economic, and environmental incentives. A microgrid is a miniature version of the central grid, only more efficient in transforming energy to electricity with lower line losses because of the closer proximity to demand. With the completion of the Institute of Electrical and Electronics Engineers' (IEEE's) Standard 1547.4-2011, microgrids could be poised to move from pilot projects to commercial reality.[120] The new standard could allow the "modern grid" to evolve into a system in which centralized generating facilities are supplemented with smaller, more distributed production using smaller generating systems, such as small-scale CHP; small-scale renewable energy sources and other DERs.

In "Grid 2030," the U.S. DOE saw microgrids as one of three cornerstones of the future grid.[121] The DOE has a long-term goal for microgrids to reduce outage time by more than 98 percent, reduce emissions by more than 20 percent and improve system energy efficiencies by more than 20 percent.[122] Microgrids may provide five benefits, including:

- improved reliability by allowing a local area to remain operational during a central grid outage or disturbance;
- relieving overload problems in the central grid by allowing the microgrid to intentionally island;
- allowing a microgrid to avoid power quality issues such as voltage distortion, voltage sag, and flicker by islanding itself;
- improving power quality for the central grid and the microgrid by reducing total harmonic distortion within the microgrid;
- allowing for maintenance on the central grid by islanding itself and continuing service to its own customers. Without a microgrid, customers would either need backup generation or go without electricity during maintenance outages.[123,124,125]

In addition, microgrids add the benefit of matching security, quality, reliability, and availability with the end-users' needs, and appearing to the electric system as a controlled entity. The development of new

---

[120] IEEE – IEEE Standards Association. July 2011. *IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems*. IEEE Standard 1547.2-2011, IEEE Standards Coordinating Committee 21, New York, New York. Accessed March 14, 2012 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5960751.

[121] DOE – U.S. Department of Energy. July 2003. *Grid 2030: A National Vision for Electricity's Second 100 Years*. Office of Electric Transmission and Distribution. Accessed April 26, 2012 at http://energy.gov/oe/downloads/grid-2030-national-vision-electricity-s-second-100-years.

[122] DOE – U.S. Department of Energy. August 2011a. *DOE Microgrid Workshop Report*. Office of Electricity and Energy Reliability, San Diego, California. Accessed April 26, 2012 at http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf.

[123] IEEE 2011.

[124] DOE 2011a.

[125] Morris G, C Abbey, G Joos, and C Marnay. 2011. *A Framework for the Evaluation of the Cost and Benefits of Microgrids*. Accessed April 26, 2012 at http://der.lbl.gov/publications/framework-evaluation-cost-benefits-microgrids.

technologies in power electronics, control, and communications,[126] along with added reliability, security, and stability and the combined values of heat and electricity through cogeneration may offset the lower costs of centralized generation.[127] Microgrids may also provide added revenues to investors where net metering and ancillary services have become developed markets. In addition, the development of microgrids will potentially reduce future utility investment in transmission and distribution infrastructure. Further, there are environmental benefits because of reduced $CO_2$, $NO_X$, and $SO_X$[128] through the better utilization of combined heat and power, which can capture as much as 85 percent of the energy used in generating electricity by also powering heating and cooling systems. The central grid, at best, is only 35 percent efficient because of electricity losses in transmission and venting heat into the atmosphere during generation.[129] In addition, microgrids can supplement power to the electric system by injecting power into the central grid during peak periods.[130] Microgrids can also achieve 99.999 percent reliability, compared with 99.9 percent reliability for the centralized grid.[131]

The definition of a microgrid is evolving somewhat from its initial concept even though that definition is still valid. Microgrids have been defined by DOE to be "a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode."[132] Key distinctions between a microgrid and distributed generation are the microgrid's ability to be islanded with coordinated control, and that it contains more than one generating source.[133] Additionally, microgrids are capable of being much larger than the IEEE 1547 standard of 10 MVA, with some estimates stating that microgrids could reach 50 megawatts (MW) before being limited by management and control issues associated with current technologies.[134] New business approaches and technologies for microgrids include the "virtual microgrid." A virtual microgrid occurs when multiple sites coordinate load and generation across the distribution system through aggregators.[135] These virtual microgrids have also been termed "virtual power plants."[136]

[126] Lasseter R, A Akhil, C Marnay, J Stephens, JE Dagle, RT Guttromson, AS Meliopoulos, R Yinger, and J Eto. 2002. *Integration of Distributed Energy Resources: The CERTS MicroGrid Concept*. LBNL-50829, Lawrence Berkeley National Laboratory, Berkeley, California. Accessed April 26, 2012 at http://www.osti.gov/bridge/servlets/purl/799644-dfXsZi/native/799644.PDF.

[127] Agrawal P, M Rawson, S Blazewicz, and F Small. 2006. "How 'Microgrids' are Poised To Alter The Power Delivery Landscape." *Utility Automation & Engineering T&D,* August, 2006. Accessed April 26, 2012 at http://www.elp.com/index/display/article-display/260536/articles/utility-automation-engineering-td/volume-11/issue-6/features/how-lsquomicrogridsrsquo-are-poised-to-alter-the-power-delivery-landscape.html.

[128] NYSERDA – New York State Energy Research and Development Authority. September 2010. *Microgrids: An Assessment of the Value, Opportunities and Barriers to Deployment in New York State*. Final Report 10-35. Accessed 5/9/2012 at http://nechpi.org/wp-content/uploads/2012/07/NYS-Microgrids-Roadmap.pdf (undated webpage).

[129] Warner G. May 2010. *Micrograds are key to future energy strategy*. The Hill News Alerts. Accessed May 7, 2012 at http://thehill.com/opinion/op-ed/95951-microgrids-are-key-to-future-energy-strategy.

[130] PSPN – Penn State Policy Notes. 2008. *Reducing Demand, Promoting Efficiency Key to Defusing Electric Rate Increases*. Center for Public Policy Research in Environment, Energy and Community Well-Being.

[131] NC – Navigant Consulting. May 2006. *Microgrids Research Assessment – Phase 2*. Final Report. Accessed April 26, 2012 at http://der.lbl.gov/sites/der.lbl.gov/files/montreal_navigantmicrogridsfinalreport.pdf.

[132] DOE – US Department of Energy. 2011b. DOE Microgrid Workshop Report. Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, Washington, D.C. Accessed November12, 2012, at http://energy.gov/sites/prod/files/Microgrid%20Workshop%20Report%20August%202011.pdf (August 2011).

[133] Lasseter RH. 2007. "Microgrids and Distributed Generation." *Journal of Energy Engineering*. Accessed April 26, 2012 at http://www.google.com/url?sa=t&source=web&cd=1&ved=0CBcQFjAA&url=http%3A%2F%2Fciteseerx.ist.psu.edu%2Fviewdoc%2Fdownload%3Fdoi%3D10.1.1.117.8039%26rep%3Drep1%26type%3Dpdf&ei=2GySTLPfEoLEsAPLkNi_Cg&usg=AFQjCNHy5mg7nXlbqafMvH0K2qajSzEHHQ.

[134] Asmus P and C Wheelock. 2012. *Microgrids: Distributed Energy Systems for Campus, Military, Remote, Community, and Commercial & Industrial Power Applications: Market Analysis and Forecasts*. Pike Research, Boulder, Colorado.

[135] NYSERDA 2010.

The DOE recommended a three-phase path to implementing microgrids in 2005. During the first phase, pilot cases examined the ability of microgrids to reduce costs of power and develop technologies to automatically connect/disconnect the microgrid to/from the central grid. Phase II pilot cases examined the security and resiliency of microgrids with higher penetration rates. Phase III is examining microgrids' ability to export power to the central grid. Each phase also addressed regulatory challenges.[137,138] Dohn, as well as Asmus and Wheelock, indicate that microgrids are poised to exit Phase III.[139,140]

Currently, most projects are pilot projects being used to validate microgrid requirements. Pike Research has indicated that significant increases in commercial microgrids cannot be far away with the adoption of IEEE Standard 1547.4-2100, (islanding standards). In fact, Pike Research estimates that there are at least 105 MW of commercial microgrids in the United States.[141]

Investments in microgrid projects made under the Smart Grid Demonstration Program (SGDP) are building on recent investments made under the Renewable and Distributed Systems Integration (RDSI) program. Together, these programs co-funded nine projects valued at over $427 million that either built microgrids or included technologies that would support microgrids. The RDSI projects are nearing completion.[142,143,144]

The CERTS microgrid at the Santa Rita, CA, jail was developed by Chevron Energy Solutions and will be the first commercial implementation of the CERTS microgrid technology. The CERTS Microgrid control logic allows the jail to continue operation should the jail's central grid connection become interrupted. The microgrid includes a 1 MW fuel cell, a 1.2 MW photovoltaic (PV) system, two 1.2 MW emergency generators, a 2 MW NaS battery and two wind turbines. The battery provides a demand offset. The microgrid was to be completed during 2011.[145]

The Borrego Springs microgrid will include advanced information-based technologies, distributed generation (DG), advanced energy storage assets, and Feeder Automation System Technology (self-healing technology). The automated distribution control will demonstrate intentional islanding.[146]

The West Virginia project will demonstrate advanced circuit control though integration of multi-agent technologies with DG, energy storage, automated load control, sensors, wireless communications, and system control technology using dynamic islanding and microgrid strategies. The DER will include

---

[136] Asmus and Wheelock 2012.
[137] Agrawal et al. 2006.
[138] NC 2006.
[139] Dohn R. 2011. *The business case for microgrids – White paper: The face of energy modernization*. Siemens. Accessed May 7, 2012 at http://www.energy.siemens.com/us/pool/us/energy/energy-topics/smart-grid/downloads/The%20business%20case%20for%20microgrids_Siemens%20white%20paper.pdf.
[140] Asmus and Wheelock 2012.
[141] Asmus and Wheelock 2012.
[142] Bossart S. 2009. Renewable and Distributed Systems Integration Demonstration Projects. Presented at the EPRI Smart Grid Demonstration Advisory Meeting, October 12–14, 2009, Albuquerque, New Mexico. Accessed July 23, 2012, at http://www.smartgrid.epri.com/doc/15%20DOE%20RDSI%20Project%20Update.pdf (undated webpage).
[143] Bossart S. 2012. DOE Perspective on Microgrids. Presented at the Advance Microgrid Concepts and Technologies Workshop, National Energy Technology Laboratory, June 7, 2012. Accessed May 13 2013 at http://www.arlevents.com/microgrids2012/briefings/7/0900-steven-bossart.pdf
[144] DOE – U.S. Department of Energy. 2012. Recovery Act Smart Grid Programs. SmartGrid.gov, Washington, D.C. Accessed November 28, 2012, at http://www.smartgrid.gov/ (undated web page).
[145] Ton et al. 2011.
[146] Ton et al. 2011.

1.2 MW of biodiesel internal combustion engines, a 250 kW microturbine, 100 kW PV, and two 500 kW energy storage units.[147]

A City of Fort Collins, CO, project will mix DER with intentional microgrid islanding. The DER will consist of 3.5 MW of PV, biofuels, thermal storage, fuel cells and microturbines, which will be aggregated.[148]

DOE laboratories are also cooperating in test bed applications for the microgrid. Lawrence Berkeley National Laboratory (LBNL) is cooperating in the CERTS microgrid concepts being undertaken at the American Electric Power test bed, Sacramento Municipal Utility District, Chevron Energy Solutions at the Santa Rita Jail and the Department of Defense projects at Fort Sill and Maxwell Air Force Base. Sandia National Laboratories is working with the U.S. Department of Defense (DOD) to apply and evaluate the Energy Surety Microgrids™ concept at Joint Base Pearl Harbor Hickam, Hawaii, Camp Smith, HI and Fort Carson, CO. Oak Ridge National Laboratory is developing controllable renewable and non-renewable DER. Pacific Northwest National Laboratory is developing GridLAB-D™, a simulation tool for operations at several levels including microgrids.[149]

The DOE also funded the Pecan Street microgrid project with funding from the *American Recovery and Reinvestment Act of 2009* (ARRA). The project, located in Austin, Texas, integrated clean energy generation, smart grid water systems, AMI, plug-in electric vehicles (PEVs), distributed storage, and smart appliances for 75 businesses and 1,000 residences.[150]

The DOD is developing microgrids with a security thrust. The Marine Corps has developed a microgrid at Twenty-nine Palms, CA, which meets DOD cyber security criteria and can island about one-third of the base's demand. The DOD does not see any impediments to microgrid deployments at their sites.[151]

### A.6.2 Description of the Metric and Measurable Elements

The following three measures have been identified as important for understanding the number of microgrids and the amount of capacity they serve.

*(Metric 6.a) the number of microgrids in operation.* Microgrids must meet the definition in Section M.6.1 above.

*(Metric 6.b) the capacity of microgrids in MW.*

*(Metric 6.c) the percentage of total grid summer capacity that is served by microgrids*. This metric measures the effect these microgrids are having on the ability of microgrids to meet electricity-supply requirements of the entire grid.

---

[147] Ton et al. 2011.
[148] Ton et al. 2011.
[149] Ton et al. 2011.
[150] Ton et al. 2011.
[151] Pellerin C. May 2012. *DOD Facilities Drive Technology for Secure Power*. PennEnergy. Accessed May 4, 2012 at http://www.pennenergy.com/index/articles/newsdisplay/1657873226.html?cmpid=EnlDailyPowerMay32012.

### A.6.3 Deployment Trends and Projections

Primarily, microgrids can be found at universities, petrochemical facilities and U.S. defense facilities. Pike Research indicated that there are more than 575 MW of microgrids located at educational campuses, primarily universities (Table A.8).[152] Using a different methodology, Resource Dynamics Corporation (RDC)[153] indicated that microgrids provided 785 MW of capacity in 2005. They noted additional microgrids that were in planning at the time as well as demonstration microgrids. RDC also noted that by examining the Energy Information Administration's database they could determine approximately 375 potential sites for microgrids if they weren't already microgrids. Pike Research indicated that they constantly find more microgrids; thus, some of the capacity of microgrids grows simply through discovery.[154] Given the EIA's net national summer generating capacity of 1,039,062 MW, the percentage of capacity met by microgrids is about 0.05 percent in 2010.[155]

**Table A.8**. Current and Forecast Capacity of Microgrids in the United States for 2011 and 2017 (MW)[156]

| Year | Commercial | Education | Government | Healthcare | Industrial | Research | Military | Total |
|---|---|---|---|---|---|---|---|---|
| 2011 | 64 | 439 | 30 | 9 | 0 | 0 | 32 | 575 |
| 2017 | 141 | 1,010 | 56 | 24 | 3 | 3 | 274 | 1,510 |

Current projections and forecasts for microgrids are as follows:

- Navigant Consulting, in their base case scenario, projected 550 microgrids installed and producing approximately 5.5 gigawatts (GW) by 2020[157] or about 0.5 percent of projected summer capacity.[158] Navigant[159] predicts a range of 1–13 GW depending on assumptions about pushes for more central power, requirements and demand for reliability from customers and whether there is an environmental requirement for carbon management. It should further be noted, however, that the considerable range of this prediction suggests the limits to which the present status of microgrids is understood.
- Pike Research estimates that in 2011 there are approximately 575 MW of capacity on microgrids operating in the United States, and anticipate that this will increase to 1.5 GW by 2017. This growth is expected to occur primarily in the Commercial, Industrial, and Institutional/Campus sectors.[160]

---

152 Asmus and Wheelock 2012
153 Resource Dynamics Corporation. 2005. *Characterization of Microgrids in the United States: Final Whitepaper*. Prepared for Sandia National Laboratories, Vienna, Virginia.
154 Asmus and Wheelock 2012
155 EIA – U.S. Energy Information Administration. November 2011a. "Table 1.1A. Existing Net Summer Capacity by Energy Source and Producer Type, 2000 through 2010." In *Electric Power Annual 2010*. Accessed June 14, 2012 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.
156 Asmus and Wheelock 2012.
157 NC 2006.
158 EIA – U.S. Energy Information Administration. June 2012. *Annual Energy Outlook 2012*. DOE/EIA-0383(2012),. Accessed June 14, 2012 at http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
159 NC 2006.
160 Asmus and Wheelock 2012.

#### A.6.3.1 Associated Stakeholders

There are numerous stakeholders associated with microgrids, but the primary stakeholders (in no particular order) include

- end-users, including distributed generation owners and customers, who need reliable, high quality power. Offsetting costs by selling excess power and/or heat has the potential to make programs more economical and attractive. Other end-users could include business parks, residential communities, apartment tenants, military installations and university campuses. All end-users are interested to some degree in the level of security that microgrids may provide, but military installations may value security above other aspects of microgrids.
- demand response aggregators or curtailment service providers who could combine multiple microgrids to meet utility ancillary services needs and/or reduced load requirements
- distribution service providers, as well as utilities and municipalities, who, depending on their size, location, and ability to integrate microgrid power production, could significantly benefit from integration of microgrid resources into their overall resource portfolio
- electric-service retailers or entities outside the microgrid that supply power to the microgrid
- the independent power producer or entity that owns the microgrid
- products-and-services suppliers of generation, control, and communications equipment that enables microgrid operation
- policy makers who need to develop regulations that balance microgrid needs with distribution service provider needs for communication of current and long-run generation and demand as well as a return on investment. Microgrids may provide policy makers with alternatives for regulating transmission and distribution investment requirements.
- policy advocates, particularly those for environmental policy
- society, who will benefit from lower pollution.

#### A.6.3.2 Regional Influences

Regional influences should not create many obstacles for microgrid development. Potential regional influences are driven more by how stakeholders in different regions of the country will interface or integrate with one another, and how regional or state regulators in the utility and environmental areas will either support or hinder development of distributed energy resources.

Microgrids can be favorable in remote places such as Alaska and Hawaii, where significant periods of islanded operation can be expected. Microgrids with CHP may be of greater value in colder climates (northern states) or regions where heating and cooling requirements are significant.

### A.6.4 Challenges to Deployment

Unfortunately, several barriers have been identified that may stifle the deployment of microgrid systems in the United States. As in other industries, regulatory barriers and their economic effects are more significant challenges to deployment than the technical challenges. While there are several regulatory barriers, the business and financial challenges listed below are those with highest impact.

#### A.6.4.1 Technical Challenges

While the business and financial challenges are more significant, there are technical challenges to moving microgrid deployments forward. The primary technical challenges include:

- Interconnection: One major barrier to the microgrid was overcome in 2011; that was the completion of standard IEEE 1547.4. The standard may not become binding for 5 to 10 years for utility operators, but it does eventually open the door for the industry. Other smart grid standards still in development that will enhance microgrids significantly are P1547.6 (interconnecting microgrids with supply distribution secondary networks), P1547.7 (impact studies for DER interconnection), and P1547.8 (implementation strategies for expanded use of IEEE 1547 standards).
- Energy storage: Standards such as IEEE P2030.2 for interoperability of energy storage systems are needed to enhance opportunities for energy storage. Energy storage standards are necessary to allow renewable energy generation.
- Integration: integrating large numbers of distributed generation resources and managing the variability of their generation while still maintaining compliance with Federal Energy Regulatory Commission-approved reliability standards.[161]
- Large-scale microgrids: as the number of interconnection points increases, large microgrids with multiple points of integration become more complicated to coordinate and protect.[162]
- Penetration level: the level of penetration could become an issue if the load served by microgrids becomes large enough that they are serving more than their own demand, and system events such as lightning strikes or other system failures cause the microgrid to respond by disconnecting from the regional grid, leaving other dependent entities without power.[163]
- Load control: controlling microgrids when renewable generation reaches 20 MW is currently difficult.[164]
- Security: some concern exists regarding the level of security, both physical and cyber, required for microgrids to be a reliable resource.[165]
- Reliability: distributed energy storage and generation hardware should not require extensive maintenance. Ideally, distributed microgrid components will be on maintenance cycles that are in line with other hardware at the installations.[166]
- Power generation types: for alternative energy resources such as renewable energy, fuel cells and microturbines, the lack of experience with system design and integration will provide technical challenges.[167,168]

---

[161] FERC – Federal Energy Regulatory Commission. July 2009. *Smart Grid Policy*. 128 FERC ¶ 61,060, p. 74. Accessed June 14, 2012 at http://www.ferc.gov/whats-new/comm-meet/2009/071609/E-3.pdf.

[162] Ye Z, R Walling, N Miller, P Du, and K Nelson. 2005. *Facility Microgrids*. NREL/SR-560-38019, National Renewable Energy Laboratory. Accessed June 14, 2012 at http://www.nrel.gov/docs/fy05osti/38019.pdf.

[163] Ye et al. 2005.

[164] Dohn 2011.

[165] NETL – National Energy Technology Laboratory. 2007. *Barriers to Achieving the Modern Grid*. U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability. Accessed June 14, 2012 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/Barriers%20to%20Achieving%20the%20Modern%20Grid_Final_v1_0.pdf.

[166] Stevens J and B Shenkman. 2009. *DC Energy Storage in the CERTS Microgrid.* Sandia National Laboratories. Accessed June 14, 2012 at http://certs.lbl.gov/pdf/microgrid-dc-storage.pdf.

[167] Ye et al. 2005.

#### A.6.4.2 Business and Financial Challenges

The most significant business and financial challenge is making the business case for microgrids. The actual costs of implementing a microgrid are still not well known. However, a recent study outlines the approach to examining the costs and benefits of microgrids, which will help quantify the business case.[169] Their methodological study provided some case studies, which indicated the cost of electricity within the microgrid was $0.161/kWh to $0.166/kWh. They also noted that when evaluating all benefits and costs, the two cases provided a positive net benefit. Other estimates of payback for microgrids indicate that two to five years is all that is required from a financial point of view, but costs are still not well known.[170] A number of DOE and DOD demonstration projects will go a long way toward providing the information required to provide the basis required for business investment. CERTS, Pareto Energy, Ltd., General Electric, Lockheed Martin Corp., Eaton Corp., Encorp LLC, Siemens Corp., and ABB microgrid technologies are near commercial stage, but do not have a track record to prove they safely match loads and frequency regulation during outages.[171]

A part of the business case includes ensuring that microgrids are not made infeasible by standby charges, interconnection policies that discourage or prohibit microgrids, or the loss of revenues faced by utilities as microgrids are deployed. The business case must also be effectively shown for the value of combined heat and electricity generation, added security, reliability, and power quality in order for investment to take place.[172] The main challenge may be to create regulations that allow the microgrid owner to capture the benefits monetarily. Significant challenges to the business case include:

- Standby charges—charges assessed to end-users on their installed capacity if it is not used solely for emergency purposes. Utilities use the standby charge to pay for the infrastructure necessary to serve the microgrid's load in the event the microgrid's generating capability becomes unavailable. These charges for rarely used infrastructure are a significant economic barrier to microgrid deployments.[173,174]
- Interconnection—the policies and procedures that describe how power-generating capacity not owned by the utility will be connected and integrated into the power grid. Without national or regional policies and procedures, utilities can develop their own policies and procedures that discourage interconnection of power-generating capacity that they do not own or control.[175,176] (See Metric 3).
- Lost utility revenues: the way the U.S. utilities are regulated, they exhibit strong economies of scale that make competition from smaller, less-efficient suppliers significantly less economical. In addition, utilities have no financial motivation to look at grid innovations that reduce their sales. Utilities have commonly raised barriers to interconnection and self-generation and also discourage energy efficiency investments because of the significant likelihood of loss of revenue and profits.[177]

---

168 NC 2006.
169 Morris et al. 2011.
170 Asmus and Wheelock 2012.
171 Asmus and Wheelock 2012.
172 NC 2006.
173 Hatziargyriou N. 2008. *Microgrids: The Key to Unlock Distributed Energy Resources?* Accessed June 14, 2012 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04505823
174 Asmus and Wheelock 2012.
175 Venkataramanan G and C Marney. 2008. "A Larger Role for Microgrids." *IEEE Power and Energy Magazine*, pp. 78–82.
176 Asmus and Wheelock 2012.
177 Venkataramanan and Marney 2008.

- Because renewable energy technologies provide a certain mainstay of microgrids, the technological and business case hurdles for energy storage will continue to hinder wide scale development of microgrids.[178]

### A.6.5 Metric Recommendations

The Pike Research Smart Grid tracker could provide continuous updates to this metric.  However, this is a private organization without a mandate for continued collection of the data; thus alternative approaches to maintaining a reliable continuous data source should be continued.

[178] Asmus and Wheelock 2012.

## A.7 Metric #7: Grid-Connected Distributed Generation and Storage

### A.7.1 Introduction and Background

This metric measures the type and quantity of grid-connected DG and energy-storage equipment. Distributed generation systems are different from the large and centralized generators that provide most of the power to the grid. Distributed generation systems can be connected to primary and/or secondary distribution voltages, are noted for their small scale [10 megavolt-amperes (MVA) or less] and proximity to the eventual end-user.[179] Fossil fuel generators, solar cells, wind turbines, and biomass applications are some of the DG technologies available to residential and rural consumers.

This metric also covers energy storage devices. Energy storage technologies include pumped hydro storage, compressed-air energy storage (CAES), batteries, flywheels, and building-level thermal storage. The aforementioned technologies provide different benefits and drawbacks and are suited to play different roles in the smart grid, from bulk energy storage for peak shaving and reliability to short duration storage for auxiliary services such as frequency regulation and voltage control.

Grid-connected storage can play a number of different roles as a part of the smart grid. In much the same way as DG, storage can replace energy supplied centrally from a service provider when the economics are most favorable. However, rather than generate electricity, storage systems merely hold and release energy in response to some external signal. The speed and duration at which a storage system can discharge energy are closely linked to the role(s) that a storage system can play in the smart grid. Potential storage roles include:[180]

- load leveling and peak shifting
- arbitrage
- load following
- frequency regulation
- renewables integration
- spinning reserves
- transmission and distribution upgrade deferral
- voltage control
- outage mitigation

The *American Recovery and Reinvestment Act of 2009* (ARRA) provided significant investment for DG and storage, awarding $185 million in support of 16 energy storage projects valued at $777 million.[181] In addition, 181 stationary electricity and energy storage devices valued at 3.6 million dollars

[179] IEEE – Institute of Electrical and Electronics Engineers. 2003. *IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems*. Accessed June 10, 2012 at http://grouper.ieee.org/groups/scc21/1547/1547_index.html (last updated December 28, 2010).
[180] Dehamna A and Bloom E. 2011. *Energy Storage and the Grid*. Pike Research, Boulder, Colorado.
[181] DOE – U.S. Department of Energy. 2012a. *Recovery Act Smart Grid Programs.* SmartGrid.gov, Washington, D.C. Accessed November 28, 2012, at http://www.smartgrid.gov/ (undated web page).

have been deployed through September 30, 2012.[182] These energy storage projects are focused on grid-scale applications of energy storage involving a variety of technologies, including advanced batteries, flywheels, and underground compressed air systems. Figures represent total cost, which is the sum of the federal investment and cost share of the recipient. The recipient cost share under ARRA must be at least 50 percent of the total overall project cost.

The ability to smoothly integrate distributed energy generation and storage delivers a key expectation of the smart grid, and the presence of such technologies offers a primary driver of many benefits associated with a smart grid. This metric, therefore, provides important insight into the overall progression toward what can be considered a truly smart energy grid.

### A.7.2 Description of Metric and Measurable Elements

Electricity from traditional service providers can be at least partially offset through the deployment of distributed generators. With net metering, excess power generated by the customer can be sold back to the electricity service provider and credited to the customer's account. Electricity sold or stored from DG will be classified into one of six categories: internal combustion, combustion turbine, steam turbine, hydroelectric, wind, and other. The metrics should not include DG or storage that is not actively managed, is not interconnected with the grid, is available only for emergency capacity, or is considered a microgrid.

The following three metrics have been identified as important aspects for understanding and quantifying grid-connected DG and storage.

*(Metric7.a) Percentage of actively managed fossil-fired, hydrogen, and biofuels distributed generation.* This metric excludes DG that is not actively managed, not interconnected with the grid, and emergency backup generation capacity that is only operated when there is an outage. Both installed megawatts (MW) and supplied megawatt-hours (MWh) are measured as a percentage of total DG and total grid generation capacity/supply.

*(Metric7.b) Percentage of actively managed batteries, flywheels, and thermal storage excluding transportation applications*. Both MW and MWh would be measured as a percentage of total storage and total grid generation capacity/supply.

*(Metric7.c) Percentage of non-dispatchable distributed renewable generation.* This metric consists of non-dispatchable, non-controllable DG fueled from renewable sources. This metric excludes renewable DG capacity not connected to the grid. Both MW and MWh would be measured as a percentage of total DG and total grid generation capacity/supply.

### A.7.3 Deployment Trends and Projections

Distributed generation capacity has been, and continues to be, a small part of total power generation. However, its role has been steadily increasing over the years. Growth since 2004 ranged from a low of 21

[182] DOE – U.S. Department of Energy. 2012. Recovery Act Smart Grid Programs. SmartGrid.gov, Washington, D.C. Accessed December 12, 2012, at http://www.smartgrid.gov/recovery_act/deployment_status/distribution (Last updated December 11, 2012).

percent as shown in EIA Form 860, *Annual Electric Generator Data*, to 360 percent for the data from Form EIA-861, *Annual Electric Power Industry Report*, from DG under 1 MW (see Table A.9).

**Table A.9**. DG Growth Since 2004[183,184]

| Year | Total Generation, EIA-861, < 10 MW | Total Generation, EIA-861, < 1 MW | Total Generation, EIA-860, < 10 MW |
|---|---|---|---|
| 2004 | 5,975 | 433 | 6,091 |
| 2009 | 16,002 | 1,132 | 7,187 |
| 2010 | N/A | 2,002 | 7,390 |

A range of numbers is used due to a recent change in the definition of DG. Through 2009, DG values were reported based on the less than or equal to 10 megavolt-ampere (MVA) definition; after 2009, the 1 MVA or less definition is used. This change was due to concern that responses were being duplicated between EIA Forms 860 and 861. Unfortunately this change makes it difficult to develop trends through the latest data year. Depending on how the data sets are combined, different results occur; due to this discrepancy in results, both data sets are presented separately in this document (see Figure A.16 and Figure A.17).

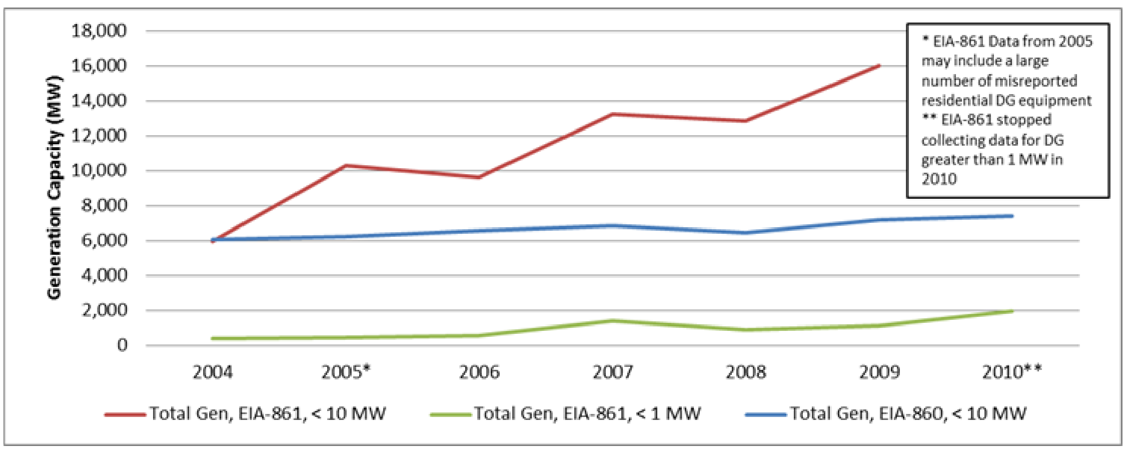



**Figure A.16**. Yearly Installed DG by Data Source[185,186]

Figure A.17 depicts the breakdown by type of DG for each year through 2010. The decrease in 2010 reflects the impact of the EIA definition change for DG, from 10 MVA down to 1 MVA, with those technologies less well suited to capacities below 1 MW (such as steam turbines) reduced in relative importance.

[183] EIA – U.S. Energy Information Administration. 2011a. *Form EIA-861 Data Files*. Independent Statistics & Analysis, Washington, D.C. Accessed June 19, 2012 at http://205.254.135.7/electricity/data/eia861/index.html. http://205.254.135.24/cneaf/electricity/page/eia861.html
[184] EIA – U.S. Energy Information Administration. 2011b. *Form EIA-860 Detailed Data*. Independent Statistics & Analysis, Washington D.C. Accessed June 19, 2012 at http://205.254.135.7/electricity/data/eia860/index.html. http://205.254.135.7/cneaf/electricity/page/eia860.html
[185] EIA 2011a.
[186] EIA 2011b.

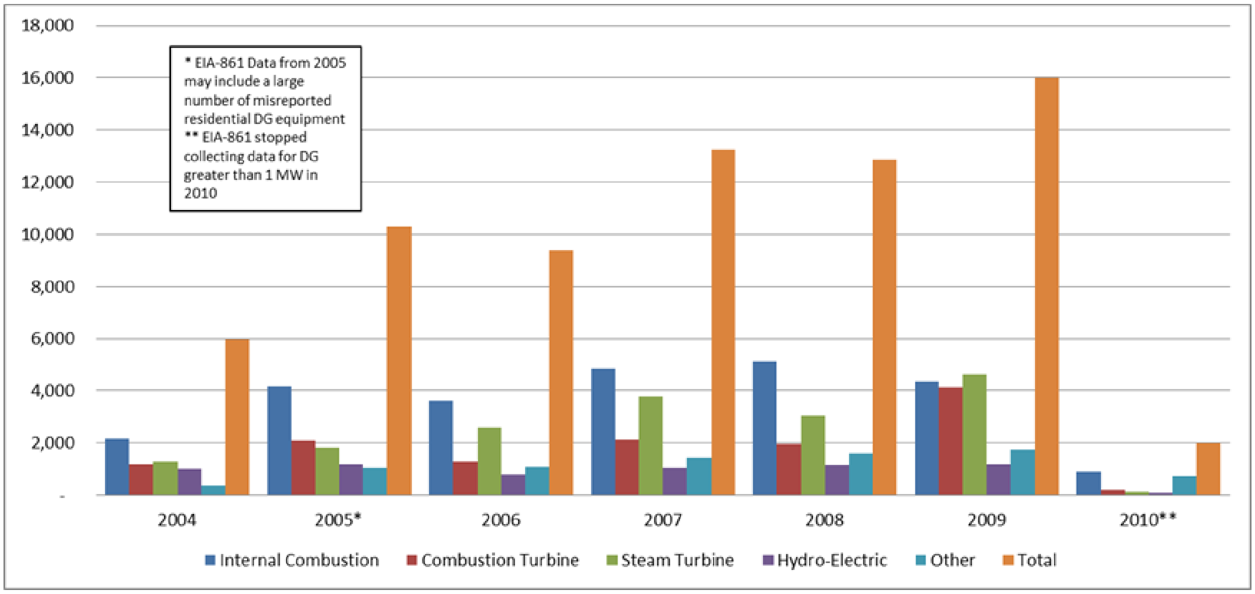



**Figure A.17**. Yearly Installed DG Capacity by Technology Type[187]

As reported in EIA-861 (see Table A.10), DG capacity from actively managed fossil-fired, hydro, and biofuels generators reached 14,273 MW in 2009, up 154 percent from 2004. Actively managed DG represents approximately 1.37 percent of total generating capacity and 89 percent of total DG. Wind and other renewable energy sources grew significantly between 2004 and 2008, increasing by 378 percent, yet they only represent 0.17 percent of total available generating capacity. Distributed wind is very small in comparison to central wind farms, which collectively registered over 39,000 MW of capacity.[188] Intermittent renewable energy resources such as wind may not be effective countermeasures for peak-demand reduction, although solar has the potential to be more coincident with summer peak-demand periods.

---

[187] EIA 2011a.

[188] EIA – U.S. Energy information Administration. January 2011c. "Table ES1. Summary Statistics for the United States, 1999 through 2010." In *Electric Power Annual 2011*, Washington, D.C. Accessed on June 19 2012 at http://205.254.135.7/electricity/annual/pdf/tablees1.pdf.

**Table A.10**. Yearly Installed DG Capacity by Technology Type[189]

| Year | Total DG (MW) | | | | Internal Combustion | Combustion Turbine | Steam Turbine | Hydro-Electric | Other |
|---|---|---|---|---|---|---|---|---|---|
| | < 10 MW | < 1 MW | Non-Backup | < 1 MW, Non-Backup | | | | | |
| **2004** | 5,975 | 433 | 5,197 | N/A | 2,168 | 1,172 | 1,270 | 1,004 | 361 |
| **2005*** | 10,312 | 506 | 9,323 | N/A | 4,163 | 2,102 | 1,830 | 1,167 | 1,050 |
| **2006** | 9,641 | 567 | 8,329 | N/A | 3,624 | 1,298 | 2,582 | 806 | 1,081 |
| **2007** | 13,254 | 1,413 | 10,844 | N/A | 4,844 | 2,134 | 3,784 | 1,051 | 1,441 |
| **2008** | 12,863 | 908 | 9,595 | N/A | 5,112 | 1,949 | 3,060 | 1,154 | 1,588 |
| **2009** | 16,002 | 1,132 | 11,783 | N/A | 4,339 | 4,147 | 4,621 | 1,166 | 1,729 |
| **2010**** | N/A | 2,002 | N/A | 1,474 | 888 | 193 | 113 | 97 | 710 |

* Distributed generator data for 2005 includes a significant number of generators reported by one respondent that may be for residential applications.
** For the year 2010 only data on generators less than 1 MW were collected.
Note: Distributed generators are commercial and industrial generators that are connected to the grid. They may be installed at or near a customer's site, or elsewhere. They may be owned either by customers or by the electricity service provider. "Other" technology includes generators for which the technology is not specified.

While DG systems have large startup costs for customers, some technologies, such as solar panels, can be easily installed on rooftops by homeowners and safely generate power for years. Solar power installed in this way has a cost ranging from $3.8 to $4.2 per installed watt.[190] Wind systems ranged from $7.5 to $2.5 per installed watt depending on the total system capacity (the higher the system capacity, the lower the installed cost per watt due to economies of scale). Biomass systems average $5.5 per installed watt of electrical generation capacity (rather than thermal generation capacity).[191]

The growth of energy storage has lagged behind that of DG, but growth of both revenue and installed capacity is forecast to be strong through 2021.[192] The vast majority of existing storage capacity is in the form of pumped hydro (see Figure A.18); a total of 39 systems currently operate in the United States with a total potential power output of up to 22 gigawatts (GW).[193] The remaining U.S. energy storage capacity is distributed across many different technologies (Figure A.19).

CAES also shows much promise for bulk energy storage, as well as ancillary services. Despite this potential, recent attempts to develop CAES projects have met with limited success; (a high-profile 270 MW project in Iowa was cancelled due to geological limitations).[194] Currently there are approximately 115 MW of installed CAES capacity in the United States.[195]

---

[189] EIA 2011a.
[190] EIA. 2013. *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Washington, D.C. Accessed on July 2013 at http://www.eia.gov/forecasts/capitalcost/ (last updated April 2013).
[191] NREL – National Renewable Energy Laboratory. June 2011. *Distributed Generation Renewable Energy Estimate of Costs and Useful Life*.
[192] Dehamna A and Bloom E. 2011. "Section 6.5.1 United States." In *Energy Storage and the Grid,* Pike Research, Boulder, Colorado.
[193] EIA 2011b.
[194] Sandia National Laboratories. January 2012. *Lessons from Iowa: Development of a 270 Megawatt Compressed Air EnergyStorage Project in Midwest Independent System Operator: A Study for the DOE Energy Storage Systems Program.* Accessed June 10, 2012 at http://www.sandia.gov/ess/publications/120388.pdf.
[195] EAC – Electricity Advisory Committee. May 2011. *Energy Storage Activities in the United States Electricity Grid*. Washington, D.C. Accessed on June 19 2012 at http://www.doe.gov/sites/prod/files/oeprod/DocumentsandMedia/FINAL_DOE_Report-Storage_Activities_5-1-11.pdf.

In addition to the bulk power storage of hydro and compressed air, flywheel technologies are being deployed to supply short periods of load-following and regulation services. There are currently 28 MW of flywheel storage installed in the United States, 20 MW of which are from a single project in New York.[196] Interviews completed for this study indicated that providers have installed storage to cover 1.3 percent of their capacity (See Appendix B).

In addition to storing electricity directly, there has also been significant investment in ways to shift the peak load to time periods with favorable economics; the most common example is cool thermal storage in buildings. Overall, thermal storage of this type represents around 4 percent of all storage capacity in the United States.[197]

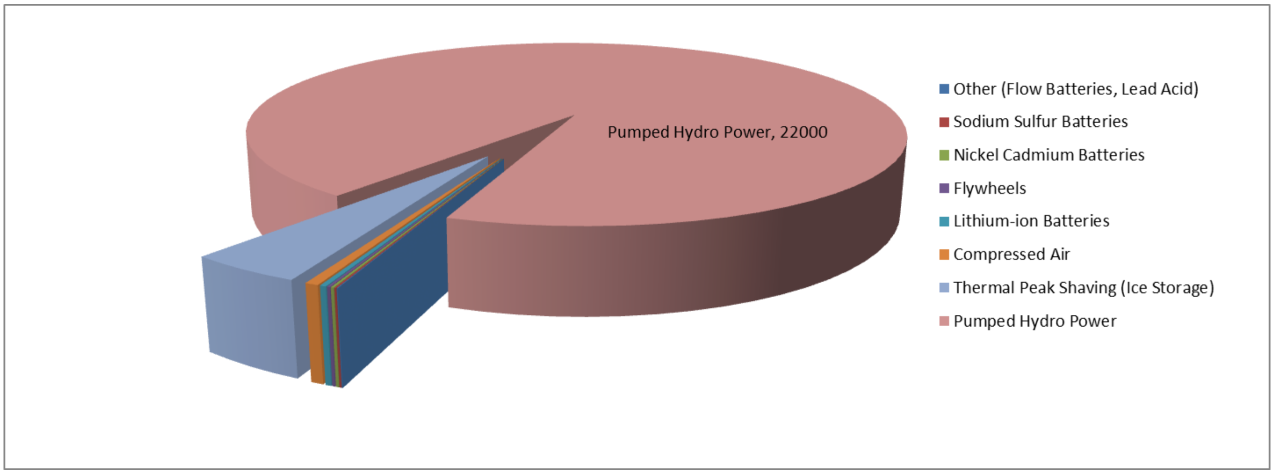



**Figure A.18**. Relative Proportions of U.S. Installed Energy Storage Technologies[198]

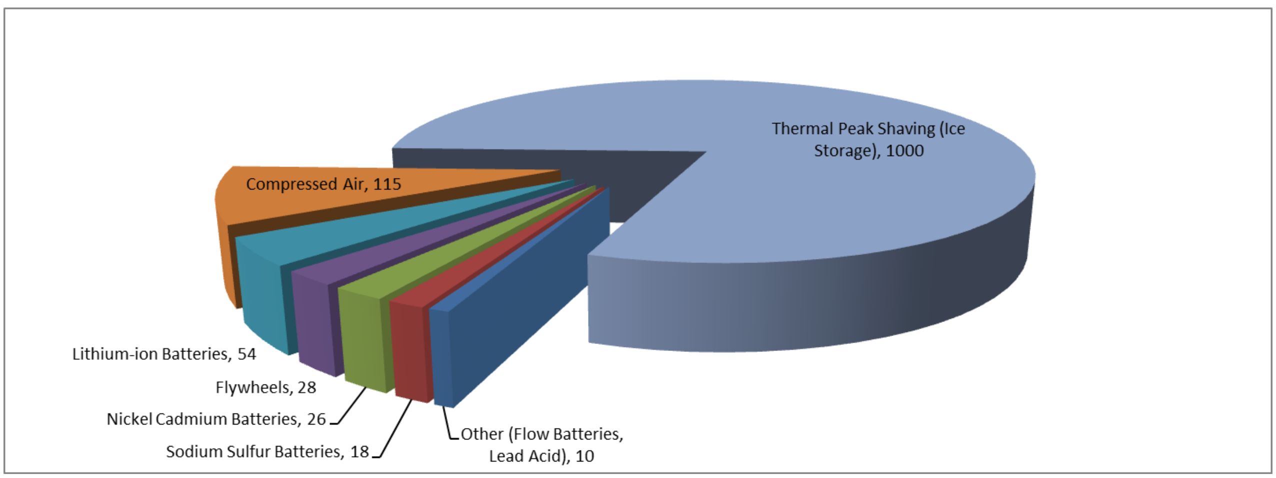



**Figure A.19**. Relative Proportions and Amounts (MW) of U.S. Installed Energy Storage Technologies, not including Pumped Storage[199]

[196] EAC 2011.
[197] NERC – North American Electric Reliability Corporation. 2011b. *2011 Reports (with 2010 Actuals)*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/page.php?cid=4|38|41 (undated webpage).
[198] EAC 2011.
[199] EAC 2011.

The EIA reports that steady growth is expected in DG through the year 2035. All sources are expected to grow by an average of 4.6 percent per year, with renewable sources (hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power) growing by 5.7 percent per year during the same period.[200]

### A.7.3.1 Associated Stakeholders

Associated stakeholders include:

- end-users (customers) – DG and storage technologies allow customers to act as both buyers and sellers in the energy market. Customers can save money by substituting their own capacity for expensive on-peak electricity[201] or temporarily reduce their household consumption and sell their electricity back into the market at high peak prices.[202] In a similar way, DG also allows end-users to only purchase energy from the grid when it meets some metric other than economics, such as the sustainability of the source. Additionally, should the grid experience technical problems or an emergency, customers can disconnect from the grid and generate their own power and/or draw from building-level storage reserves.[203]
- distribution service providers or electricity service provider companies – Electricity service provider companies face a different set of risks than end-users. While DG offers the grid access to quick and inexpensive resources that expand grid flexibility and capacity,[204] DG will also require a significant investment of resources to manage the quality of the power being supplied, as well as the purchase of new infrastructure to dispatch DG resources. However, DG can be used as a way to defer capital expansion and facilitate retirement of old units by accommodating peak load conditions.[205]
- manufacturers of DG and storage devices – Suppliers will have a stake in developing lower-cost technologies and making those devices more cost effective.
- balancing authorities – Balancing authorities are important stakeholders as non-dispatchable renewable generation grows as a proportion of total grid generation capacity; balancing authorities are also well placed to take advantage of the ancillary services that can be provided by certain storage technologies.
- transmission providers – Transmission providers will also have a stake as DG grows to be a larger proportion of the total generation capacity and they need control for power-quality issues. However, modern power electronics and some electrochemistries have the ability to rapidly charge and discharge. This ability could be used as a means to address the dual goals of increasing effective transmission capacity and improving transmission grid reliability.[206]

---

[200] EIA – U.S. Energy information Administration. 2011d. *Annual Energy Outlook 2011*. Independent Statistics & Analysis, Washington, D.C. Accessed on June 19 2012 at http://205.254.135.7/forecasts/archive/aeo11/.

[201] Hall J. October 1, 2001. "The New Distributed Generation." *Connected Planet*. Accessed June 11, 2012 at http://connectedplanetonline.com/mag/telecom_new_distributed_generation/.

[202] Cogeneration Technologies. ca. 1999. *Distributed Generation*. Accessed June 11, 2012 at http://www.cogeneration.net/Distributed_Generation.htm (undated webpage).

[203] Cogeneration Technologies 1999.

[204] Cogeneration Technologies 1999.

[205] EAC – Electricity Advisory Committee. December 2008. *Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid*. U.S. Department of Energy, Washington, D.C. Accessed July 11, 2012 at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/final-energy-storage_12-16-08.pdf.

[206] EAC 2008.

However, for these goals to be met, careful consideration of project attributes, such as siting, must be made.[207]

- local, state, and federal energy policy makers – Policies on DG and storage interconnection standards may need to be developed.
- standards organizations and their developers – Responses to policy makers on DG interconnection standards will need to be developed.

#### A.7.3.2 Regional Influences

States and regions may have different regulations for the quality of the power being sold or how the power is produced. Some states may value DG capacity differently from others and offer different subsidies and/or taxes based on those values. For example, Oregon State law has specific plant site-emissions standards for minor sources emitting pollutants such as nitrogen oxides ($NO_x$), $SO_2$, CO, or particulate matter (PM), whereas Ohio relies on the Best Available Technology (BAT) standard with specific limitations for PM and $SO_2$ based on location, unit type, and size.[208] Additionally, in accordance with the U.S. Federal Government's Green Power Purchasing Goal laid out in the *Energy Policy Act of 2005*, states tend to offer the most incentives for DG projects that use recognized renewable energy sources.[209]

### A.7.4 Challenges to Deployment

Distributed generation presents significant technical, business, and legal challenges for the grid. The technical challenges include integrating DG resources while maintaining the level and quality of voltage and fault protection coordination. Business and financial challenges include the costs to utilities of integrating DG resources and providing a system flexible enough that consumers can afford to recover investments in DG resources.

#### A.7.4.1 Technical Challenges

Technical challenges to deployment include:

- standardization of the DG system interface with the grid
- operation and control of the DG (DG may also make fault detection more difficult)[210]
- planning and design
- voltage regulation.[211]

[207] Sandia National Laboratories 2012.
[208] EEA – Energy and Environmental Analysis, Inc. 2008. *Economic Incentives for Distributed Generation*. Accessed July 9, 2012 at http://www.eea-inc.com/rrdb/DGRegProject/Incentives.html (undated webpage).
[209] DSIRE – Database of State Incentives for Renewables & Efficiency. 2011. *Federal Incentives/Policies for Renewables & Efficiency: U.S. Federal Government - Green Power Purchasing Goal*. Accessed June 5, 2012 at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US01R&State=Federal&currentpageid=1 (last updated July 27, 2011).
[210] Driesen J and R Belmans. 2006. "Distributed Generation: Challenges and Possible Solutions." In *Proceedings of the 2006 IEEE Power Engineering Society General Meeting*, June 18–-22, 2006, Montreal, Quebec. Institute of Electrical and Electronics Engineers, Piscataway, New Jersey.

Both the DG and storage resources considered here share monitoring and control challenges similar to those identified for metrics discussing demand response.

The system interfaces associated with incorporating DG resources differ widely between technologies. Internal combustion engines, combustion turbines, and small hydropower generation require synchronous or induction generators to convert to the prime source and power frequency. Fuel cells, wind turbines, photovoltaics and batteries require inverters. The challenge is to bring the sources on line while maintaining system voltage and frequency. In addition, inverters used to transform direct current (DC) power generation units to alternating current (AC) power units can increase harmonics in the grid.[212]

Voltage regulation challenges require more than changing a transformer. The problem will include overvoltage issues that can arise due to ungrounded DG-connected generation.[213] DG will also present technical hurdles in terms of frequency, voltage level, reactive power, and power conditioning.[214]

Fault detection and protection may become more difficult with increased DG. Since electricity usually flows from areas of high voltage to low voltage, it may become more difficult to detect faults when fault current comes from either the main power system or from the DG unit.[215] This technical challenge means that in case of fault detection, DG units usually are removed from the grid first, which could have business impacts, as discussed in the next section.

Storage technologies face many of the same interconnection[216] and power quality issues as DG. In addition, specific storage technologies face their own challenges, including short lifetimes and environmental issues for batteries and materials properties for flywheels. Flow batteries do have long lifetimes, but are only recently beginning to move beyond field trials.[217] Nickel metal hydride batteries also have long lifetimes, but have lower energy density. Sodium-sulfur batteries have shown promise in electricity service provider applications, but are limited by safety issues and associated exacting design requirements. Additionally, the cycle efficiencies of batteries are in the range of 70 percent to 85 percent, which indicates that 15 to 30 percent of energy stored is lost.[218]

### A.7.4.2 Business and Financial Challenges

Making the grid compatible with DG systems could be expensive for system operators. System operator investment in equipment that integrates DG, microgrids and storage systems is complicated by the fact that predicting the amount of energy transmitted or generated by many of these technologies is

---

211 Lawrence CP, MMA Salama, and R Shatshat. 2009. "Studying the "Effects of Distributed Generation on Voltage Regulation," *International Journal of Electrical Engineering Education* 46:11–-29, Waterloo, Ontario, Canada. Accessed on June 19 2012 at http://www.lib.sie.edu.cn/tools/ebsco/f1.pdf.
212 Driesen and Belmans 2006.
213 Eynon RT. 2002. *The Role Of distributed Generation in U.S. Energy Markets.* Energy Information Administration, Washington, D.C. Accessed June 18, 2012 at http://www.eia.gov/oiaf/speeches/dist_generation.html.
214 Driesen and Belmans 2006.
215 Driesen and Belmans 2006.
216 Sliker 2009.
217 Wald M. May 2012. "Is That Onions You Smell? Or Battery Juice?" In *New York Times Green Blog,* New York, New York. Accessed June 19, 2012 at http://green.blogs.nytimes.com/2012/05/09/is-that-onions-you-smell-or-battery-juice/.
218 APS – American Physical Society. 2007. *Challenges of Electricity Storage Technologies.* APS Panel on Public Affairs, Committee on Energy and Environment,. College Park, Maryland. Accessed June 5, 2012 at http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf (undated webpage).

often difficult, making investment recovery limited and uncertain. There will also be a need for instrumentation and communication to make the DG resources dispatchable. These costs could vary from one electricity service provider to another;[219] please see Metric 3 for a discussion of the business and financial challenges presented by a lack of standard interconnection agreements.

Energy storage technologies could be used to access a number of value streams, including capital investment deferral, deployment of expanded intermittent renewable energy sources, and energy maintenance achieved through islanding (power provided independently from the electricity service provider). To achieve these benefits, however, storage systems in the one- to four-hour runtime range are needed, either through improvements in existing technologies or the development of new technologies.[220]

Distributed generation can be brought online much more quickly than more traditional utility-sized generation, with lower total capital costs. However, the costs per kW are higher and the overall costs of per kWh produced are usually higher than for grid-supplied base-load power. In addition, with the greater flexibility associated with DG comes the risk of less grid stability. When DG is a relatively small fraction of the grid, its impact is relatively small, but as DG penetration increases, reliability could potentially degrade due to voltage fluctuations and reactive-power issues. However, other studies show that when DG is set up properly, greater grid reliability can be achieved since pockets of a smart grid can operate as islands in the event of a total grid collapse. Firms may need to take these considerations into account when evaluating the costs and benefits of buying and providing electricity for their businesses.[221] For example, DG may serve as a hedge against grid price fluctuations or power-quality uncertainty: as prices trend upward with tightening supply-demand balances, or if power quality begins to fall, DG owners may opt to produce their own electricity.[222]

The use of DG will also depend upon the supply and relative price of alternative fuels. Increasing fuel prices for small combustion generators or the intermittent nature of some renewable energy sources may make the economic feasibility of DG fluctuate, and it may not be available to meet short-term needs. However, with flexible pricing schemes, shortfalls in grid-supplied capacity can be mitigated by rising prices.

### A.7.5 Metric Recommendations

No data were found on the kWh of grid-connected DG. The value may not currently be available, but should become so with more advanced metering. In addition, the EIA electric power production information could be improved with an indication of the portion of power production that is dispatchable as opposed to variable resources. Also, a recent change in how data is collected for EIA Form 861 appears to leave out a significant portion of DG resources; by only collecting data on DG equipment rated at 1 MVA or less, it appears that some equipment is not being tracked on either EIA-860 or -861. In the future the survey should be designed to capture all DG under 10 MVA. The survey should be modified to

---

[219] OE – Office of Electricity Delivery and Energy Reliability. June 2008. *Metrics for Measuring Progress Toward Implementation of the Smart Grid: Results of the Breakout Session Discussions at the Smart Grid Implementation Workshop*. Prepared by Energetics Incorporated, June 19-20, 2008, Washington, D.C. Accessed June 11, 2012 at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Smart_Grid_Workshop_Report_Final_Draft_07_21_09.pdf (undated webpage).
[220] EAC 2008.
[221] Driesen and Belmans 2006.
[222] LeMaire X. 2007. "Regulation and Distributed Generation." Presented at the ERRA Integration Workshop,. July 6, 2007, Budapest, Hungary. Accessed June 11, 2012 at www.un.org/esa/sustdev/csd/csd15/lc/reep_regulation.pdf

break out individual generator equipment details such as prime-mover technology and equipment status (standby, backup, etc.). If data were collected at the equipment level as in EIA-860, rather than in aggregate by owner, a much clearer understanding of the state of DG penetration would be possible.

# A.8 Metric #8: Market Penetration of Electric Vehicles and Plug-In Hybrid Electric Vehicles

## A.8.1 Introduction and Background

This metric examines the penetration of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) into the light-duty vehicle market. This metric includes extended range electric vehicles (EREVs) but not hybrid electric vehicles (HEVs). The vehicle types measured in this metric are often referred to collectively as PEVs. Light-duty vehicles include automobiles, vans, pickups, and sport utility vehicles with a gross vehicle weight rating of 8,500 pounds or less.[223] EVs are powered exclusively by electric drivetrains. A PHEV is an HEV with batteries that can be recharged when plugged into an electric outlet as well as an internal combustion engine (ICE) that can be activated when batteries require recharging. EREVs, like PHEVs, have both an electric motor and ICE. Unlike PHEVs, however, EREVs do not use the ICE to directly power the vehicle.

President Obama announced an ambitious initiative designed to put 1 million advanced technology vehicles on U.S. roads by 2015. Reaching this goal could reduce dependence on foreign oil by as much as 750 million barrels through 2030. To achieve the goal, several federal initiatives were established to support the development of advanced technology vehicles in the U.S.:

- The *American Recovery and Reinvestment Act of 2009* included a $2.4 billion program designed to establish 30 manufacturing facilities for EV batteries and components. For each dollar of federal funds invested in the program, private partners are required to invest at least one dollar.
- President Obama issued Executive Order 13514, which requires federal agencies to set targets for 2020 greenhouse gas emissions and calls for a 30 percent reduction in petroleum consumption by the federal vehicle fleet by 2020.
- The U.S. DOE's Advanced Research Projects Agency-Energy (ARPA-E) is providing an additional $80 million to transformative research and development projects designed to advance battery- and electric-drive component technology beyond current frontiers.
- The Advanced Technology Vehicle Manufacturing (ATVM) Loan Program was established, and as of March 2012 had provided $8.4 billion in loans in support of advanced vehicle technologies and associated components. The ATVM Loan Program has the authority to issue an additional $16 billion in loans. Under the ATVM program, the federal government provided a $5.9 billion loan to the Ford Motor Company to upgrade factories and increase the fuel efficiency of more than a dozen vehicles. Nissan secured a $1.4 billion loan under the ATVM program to retool its Smyrna, Tennessee, facility to build an advanced battery manufacturing plant.
- ARRA co-funded the installation of 775 electric vehicle charging stations.[224]

[223] The definition of light-duty vehicles includes motorcycles. Although electric motorcycles are commercially available, plug-in hybrid motorcycles are unlikely to be pursued as a product. Therefore, we omitted motorcycles from this analysis.
[224] DOE – U.S. Department of Energy. 2012a. Recovery Act Smart Grid Programs: Deployment Status. SmartGrid.gov, Washington, D.C. Accessed December 14, 2012, at http://www.smartgrid.gov/recovery_act/deployment_status (last updated December 13, 2012).

- In March 2012, President Obama and Secretary Chu launched the EV Everywhere challenge consisting of a series of workshops across the U.S. designed to discover and discuss approaches and technologies that can achieve breakthroughs in reducing the costs associated with EVs and associated components.
- President Obama has also recommended converting the $7,500 tax credit for PEVs into a rebate that consumers could redeem at the point of sale.

As PEVs penetrate the motor vehicle marketplace, their integration with the electric grid will be made possible through smart grid applications, including smart charging technologies, infrastructure enabling bidirectional flows of information, and advanced metering infrastructure. This integration raises challenges but also will provide benefits. Figure A.20 illustrates the bidirectional interaction between PEVs and the smart grid.


**Figure A.20**. PEV Integration into Smart Grid[225]

While challenges to PEV integration exist even when implemented with load management technologies, PEVs have the potential to yield significant benefits through reduced emissions and reductions in dependence on foreign oil. In addition, PEVs used in conjunction with smart grid elements could be used to advance energy storage capabilities, which could support expanded deployment of intermittent renewables, including wind and solar generation.

[225] PNNL – Pacific Northwest National Laboratory. 2011. *Using Smart Grids to Enhance Use of Energy-Efficiency and Renewable-Energy Technologies.* PNNL-20389, prepared for the Asia-Pacific Economic Cooperation Energy Working Group Richland, Washington. Accessed July 12, 2012 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-20389.pdf.

## A.8.2 Description of Metric and Measurable Elements

*(Metric 8) The total number and percentage shares of on-road light-duty vehicles—comprising EVs and PHEVs.*[226] It also measures EV and PHEV penetration of the light-duty vehicle market, expressed as a percentage of new vehicle sales.

## A.8.3 Deployment Trends and Projections

Table A.11 presents estimates of EVs and PHEVs currently in use and projected out to 2030 based on the EIA's Annual Energy Outlook (AEO) 2012. This outlook, which is considered the AEO's reference case, is conservative and does not consider potential future tax credits or other incentives. Other, more aggressive scenarios consider high economic growth, reduced EV costs, and accelerated growth in oil prices.

Based on EIA data, the number of EVs operating on-road in the U.S. was 21,601 in 2010 compared to 26,823 in 2008. EVs represented roughly 0.01 percent of all light-duty vehicles in use in 2010. EV sales were small in 2010, representing two-tenths of one percent of the light-duty-vehicle market share.[227] No PHEV sales were registered by the EIA in 2010; however, PHEV sales are forecast in the reference case to reach 144,680 (0.93 percent of light-duty vehicle sales) by 2020 and 199,957 (1.2 percent of light-duty vehicle sales) by 2030.

As shown, the number of light-duty EVs in use is forecast in the reference case to grow to 1.2 million (0.47 percent of light-duty vehicle sales) by 2030. PHEVs operating on-road are forecast to reach 2.2 million or 0.83 percent of the light duty vehicle stock by 2030.[228]

**Table A.11**. EV and PHEV Market Penetration[229]

| Year | EVs On-Road | | PHEVs On-Road | | EV Sales | | PHEV Sales | |
|---|---|---|---|---|---|---|---|---|
| | Total in Use | % of Light-Duty Vehicles | Total in Use | % of Light-Duty Vehicles | Total Sales | % of Light-Duty Market | Total Sales | % of Light-Duty Vehicles |
| 2008 | 26,823 | - | - | - | 120 | - | - | - |
| 2010 | 21,601 | 0.01% | - | 0.00% | 1,837 | 0.02% | - | 0.00% |
| 2015 | 34,093 | 0.02% | 182,076 | 0.08% | 6,183 | 0.04% | 75,212 | 0.49% |
| 2020 | 111,805 | 0.05% | 792,778 | 0.34% | 38,064 | 0.24% | 144,680 | 0.93% |
| 2025 | 484,904 | 0.19% | 1,481,710 | 0.59% | 103,465 | 0.61% | 172,886 | 1.03% |
| 2030 | 1,243,157 | 0.47% | 2,190,494 | 0.83% | 208,910 | 1.22% | 199,957 | 1.17% |

In addition to the AEO reference case, EIA also constructed a high-technology-battery case, which assumed that battery storage prices would fall from $304 to $135 per kilowatt-hour by 2035. In the high-technology-battery case, the prices of HEVs and PHEVs with a 10-mile all-electric range were

227 EIA – U.S. Energy Information Administration. 2012a. "Supplemental Tables 57 (Total United States) and 58 (Light-Duty Vehicle Stock by Technology Type)." *Annual Energy Outlook 2012*. Washington, D.C.
228 EIA 2012a.
229 EIA 2012a.

assumed to be 5 percent lower than in the reference case. For EVs with 100- and 200-mile all-electric ranges, the prices were assumed to be 13 percent and 30 percent lower, respectively. The prices for PHEVs with a 40-mile all-electric range were assumed to be 11 percent lower in the high-technology-battery case. Using the high-technology-battery case assumptions, PEV sales are forecast to reach 13.3 percent of U.S. light-duty vehicle sales by 2035. Further, combined PEV and HEV sales are forecast to reach 24.3 percent of all light-duty vehicle sales by 2035, compared to 8 percent under the reference case.[230]

After years of speculation, consumer acceptance of the EV and PHEV is finally being put to the test. In 2010, Nissan introduced the LEAF to the U.S. market. The Nissan LEAF, which is an EV, had a manufacturer's suggested retail price (MSRP) of as low as $32,780, or $25,280 after netting out all federal tax credits. The 2012 LEAF is offered at an MSRP of as low as $35,200, or $27,700 after federal tax credits.

In 2011, Chevrolet introduced the Volt, which is a PHEV. The 2011 Volt was offered at an MSRP of as low as $41,000, or $33,500 after federal tax credits. The 2012 Volt has come down in price and is sold at an MSRP of as low as $39,145, or $31,645 after netting out federal tax credits. In addition, there are several companies that perform aftermarket PHEV conversions, including Amberjac Projects, 3Prong Power, EEtrex, Inc., Enginer, Inc., Hybrid Electric Vehicle Technologies, Inc., Hymotion, Plug-in Conversions Corp., and Plug-In Supply.

In addition to the aforementioned PEV models, there are many others that have been introduced or are expected to be introduced shortly into the U.S. market. Table A.12 presents a list of new and upcoming PEV models. For each model, the vehicle type and availability are documented. The variety of designs, price levels, and battery ranges will provide consumers with more PEV options in the coming years. As these options find appeal within specific market segments, vehicle sales and penetration rates will be expected to grow.

[230] EIA 2012a.

**Table A.12**. Existing and Upcoming EVs and PHEVs[231]

| Vehicle Make / Model | Vehicle Type | Availability |
|---|---|---|
| BMW i3 | EV | Available now |
| BMW i8 | PHEV | Available in 2014 |
| Cadillac ELR | PHEV | Available now |
| Chevrolet Spark | EV | Available now |
| Chevy Volt | PHEV | Available now |
| Fiat 500e | EV | Available now |
| Ford C-Max Energi | PHEV | Available now |
| Ford Focus Electric | EV | Available now |
| Ford Fusion Energi | PHEV | Available now |
| Honda Accord Plug-in Hybrid | PHEV | Available now |
| Kia Soul EV | EV | Available in 2014 |
| Mercedes B-Class Electric Drive | EV | Available in 2014 |
| Mitsubishi I-MiEV | EV | Available now |
| Nissan LEAF | EV | Available now |
| Porsche Panamera S E-Hybrid | PHEV | Available now |
| Smart Electric Drive | EV | Available now |
| Tesla Model S | EV | Available now |
| Tesla Model X | EV | Available in 2015 |
| Toyota Rav4 EV | EV | Available now |
| Toyota Prius Plug-in Hybrid | PHEV | Available now |
| Volkswagen E-Golf | EV | Available in 2014 |

In the past 5 years, the HEV market has expanded significantly while PEVs have neared market readiness. The PEV market remains in its nascent stage, but as the first wave of PEVs hit the market, sales began to register. In 2011, PEV sales exceeded 2,700 while total HEV sales topped 266,300. In 2012, HEV sales in the U.S. reached 434,645 while PHEV and EV sales were 38,584 and 14,251 in 2012. Total combined HEV and PEV sales during 2012 reached 487,480 or 3.4 percent of the U.S. light-duty vehicle market.[232] While the DOE reference-case forecasts exceeded actual sales for HEVs and PEVs in 2011 (317,800 vs. 286,367), market penetration rates in 2012 (3.4 percent) have exceeded DOE forecasts (2.5 percent).[233]

The presence of EV charging stations (Level 2 and Level 3) facilitates the operation of EVs and encourages their adoption. As of November 2012, there were 14,594 public and private EV charging stations located in the U.S.[234] ARRA encouraged EV penetration by co-funding projects that installed 775 EV charging stations.[235]

To express the emerging PEV vehicle stock in terms of electric energy consumption [kWh] and electric demand [kWh], a simple equivalency can be established applying the following set of assumptions:

[231] Plugincars.com. 2014. Electric Cars and Plug-in Hybrid. Accessed June 3, 2014, at http://www.plugincars.com/cars.
[232] Electric Drive Transport Association. 2013. *Electric Drive Vehicle Sales Figures (U.S. Market) – EV Sales*. Accessed on October 17, 2013 at http://electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952 (undated webpage).
[233] EIA 2012a
[234] DOE, Energy Efficiency & Renewable Energy. 2012b. *Alternative Fueling Station Counts by* State. Alternative Fuels Data Center. Accessed June 25, 2012 at http://www.afdc.energy.gov/fuels/stations_counts.html (webpage last updated July 2012).
[235] DOE 2012b

- Miles driven electrically per PEV on average: 33 miles
- Energy efficiency of a PEV: 0.3 kWh/mile
- Level 1 charging demand: 1.8 kW (120V*15A) with a diversity factor of 0.5
- Level 2 charging demand: 3.3 kW (220V*15A) with a diversity factor of 0.5
- DC charging: 60 kW (480V*125A) with a diversity factor of 0.1

Given these assumptions, the PEV fleet for the two years of commercial availability (through May 2012) amount to 17,219 (2,700+10,708+3,811) with an estimated total electric energy consumption of approximately 170 MWh and an estimated electricity demand of 15 MW, assuming all vehicles use Level 1 charging. The estimate is increased to 22 MW if 50 percent charge at Level 1 and 50 percent at Level 2, and 32 MW if 30 percent charge at Level 1, 60 percent at Level 2, and 10 percent perform DC charging.

The EIA reference-case forecast presented in the 2012 AEO is conservative compared to a number of recent forecasts prepared by industry. While some forecasts estimate ultimate HEV and EV penetration of the light-duty vehicle market in the 8 to 16 percent range,[236] the EPRI and the Natural Resources Defense Council (NRDC) were more aggressive, estimating PHEV market penetration rates under three scenarios, ranging from 20 to 80 percent (medium PHEV scenario estimate of 62 percent) in 2050. EPRI and NRDC used a consumer-choice model to estimate market penetration rates.[237]

The findings of the EPRI and NRDC study, as well as those for several other EV and PHEV market penetration studies, are presented in Figure A.21. Note that there are multiple estimates from several studies, representing forecast penetration rates at various points in the future. Further, some of the studies presented a range of estimates for single points in time based on various policy or technology assumptions; these studies are designated through high-low points connected with lines in the graph.

The report identified as "PNNL" in Figure A.21 was prepared for DOE by Pacific Northwest National Laboratory (PNNL) in 2008. The report presented and examined a series of PHEV market penetration scenarios given varying sets of assumptions governing PHEV market potential. Based on input received from technical experts and industry representatives contacted for the report as well as data obtained through a literature review, annual market penetration rates for PHEVs were forecast from 2013 through 2045 for three scenarios. Figure A.21 presents the results of the "R&D Goals Achieved" scenario. The goals underpinning this scenario include a $3,400 marginal cost of PHEV technology over existing HEV technology, a 40-mile all-electric range, 100 miles per gallon equivalent, and PHEV batteries that meet industry standards regarding economic life and safety. Under this scenario, PHEV market penetration was forecast to ultimately reach 30 percent, with 9.9 percent achieved by 2023 and 27.8 percent reached by 2035.[238]

---

[236] Greene DL, KG Duleep, and W McManus. 2004. *Future Potential of Hybrid and Diesel Powertrains in the U.S. Light-Duty Vehicle Market.* ORNL/TM-2004/181, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed November 24, 2008 at http://www.ornl.gov/~webworks/cppr/y2004/rpt/121097.pdf.

[237] EPRI – Electric Power Research Institute, National Resources Defense Council (NRDC), and Charles Clark Group. 2007. *Environmental Assessment of Plug-in Hybrid Electric Vehicles – Volume 1: Nationwide Greenhouse Gas Emissions.* Palo Alto, California.

[238] Balducci P. 2008. *Plug-in Hybrid Electric Vehicle Market Penetration Scenarios*. PNNL-17441, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 22, 2010 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17441.pdf (undated webpage).

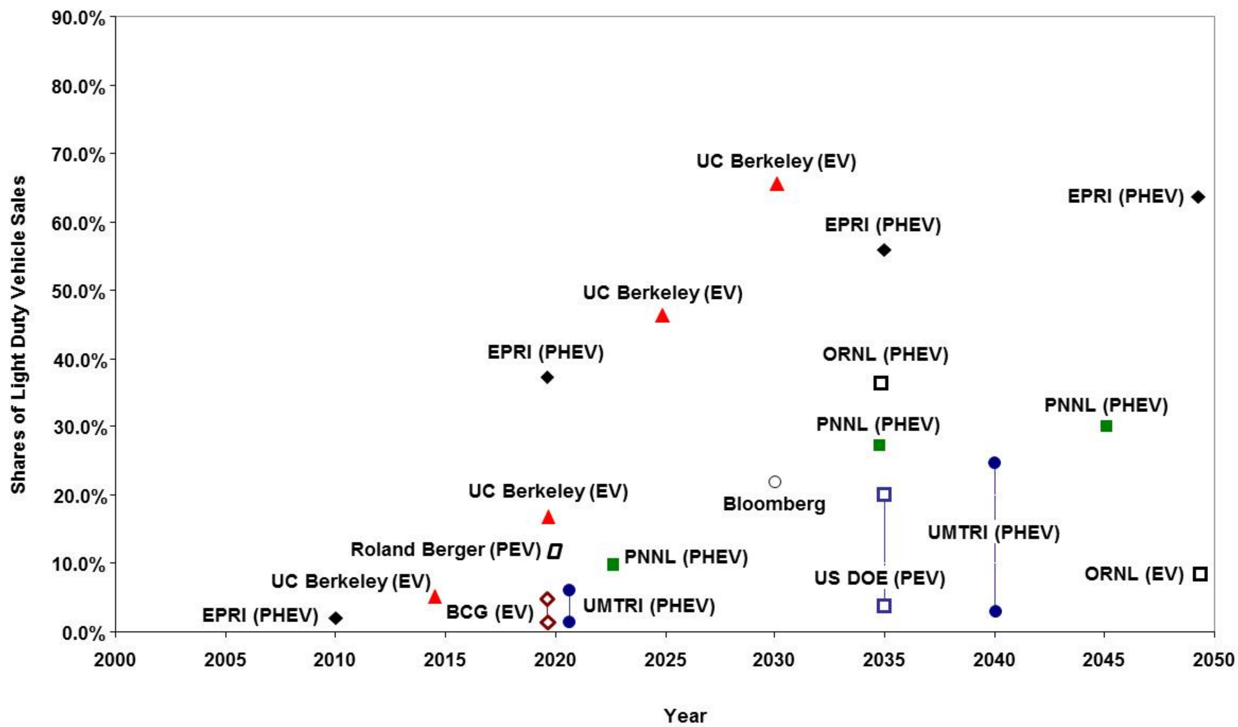



**Figure A.21**. PHEV Market Penetration Scenarios

The report prepared by the University of Michigan Transportation Research Institute (UMTRI) relied on an agent-based model that simulated the automotive marketplace through interactions between automotive consumers, fuel producers, vehicle producers/suppliers, and government agencies. The interactions between these four classes of decision makers were modeled based on individual objectives and needs. The agent-based model designed for this study estimated PHEV market penetration rates of 1 to 3 percent (fleet penetration of approximately 1 percent) by 2015, 1 to 5 percent (fleet penetration of 1 to 3 percent) by 2020, and 1 to 25 percent (fleet penetration of 1 to 20 percent) by 2030. The scenarios presented in the UMTRI report are differentiated based on assumptions regarding original equipment manufacturer (OEM) subsidies and sales tax exemptions. As OEM subsidies and sales tax exemptions are applied, the agent-based model estimates larger market shares for PHEVs.[239]

A report prepared by Greene and Lin at Oak Ridge National Laboratory (ORNL) used a consumer-choice model to estimate the market penetration of competing alternative technologies under two competing scenarios: a) a base case that maintains the current policy environment calibrated to the 2009 AEO Updated Reference Case, and b) a case that assumes that the goals of the DOE FreedomCAR program are achieved. Under the base case scenario, PHEV sales reach 1 million (5.1 percent of light-duty vehicle sales) by 2037 and 3 million (12.5 percent of light-duty vehicle sales) by 2050. Under the FreedomCAR Goals case, PHEV sales would grow more rapidly, reaching 1 million (6.0 percent of light-duty vehicle sales) by 2020 and 7 million (36.9 percent of light-duty vehicle sales) by 2050. Also,

[239] Sullivan JL, IT Salmeen, and CP Simon. 2009. *PHEV Marketplace Penetration: An Agent Based Simulation.* UMTRI-2009-32, prepared by the University of Michigan Transportation Research Institute for the U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://hdl.handle.net/2027.42/63507 (undated webpage).

EV sales reach 2 million, or 8.3 percent of light-duty vehicle sales, in 2050 under the FreedomCAR Goals case.[240] The findings of the FreedomCAR Goals Case are presented in Figure A.20 labeled as "ORNL."

The study prepared by Becker and Sidhu of the University of California, Berkeley's Center for Entrepreneurship and Technology adapted the Bass model, which has been used to forecast market penetration for other new technologies, to an EV with switchable batteries, which when discharged can be replaced with a charged battery rather than stopping to recharge. The market for an EV with switchable batteries was established using survey data on U.S. driving patterns given differing assumptions regarding oil prices. The adapted Bass model was then used to estimate technology adoption rates. Based on the survey data underpinning the analysis and increasingly aggressive oil price assumptions, Becker and Sidhu estimated market penetration rates for the EV with switchable batteries of 64 to 85 percent by 2030. The low-end estimate relies on oil price data presented in the EIA AEO's reference case, while higher-end estimates use the EIA high oil price case and assume operator subsidies.[241]

In addition to the aforementioned studies, Figure A.21 presents the findings of the Boston Consulting Group's study of EV penetration (labeled "BCG"), which estimated market penetration of 1 to 5 percent in the U.S. by 2020. Additionally, the figure presents the forecast 2035 penetration rate for PEVs presented in EIA's 2012 AEO. The range presented represents the difference between the reference and high-technology-battery cases.[242]

There are a number of recent PEV market penetration studies that were not added to Figure A.21 due to space constraints and the groupings of estimates around certain years (e.g., 2020). These studies are, however, worthy of mention. Deloitte Consulting recently estimated that PEV market penetration would reach 3.1 percent of light-duty vehicle sales by 2020 under its probable scenario.[243] J.D. Power and Associates estimated 7 percent market penetration rates for combined hybrid and basic electric vehicle sales in 2020.[244] The findings of a market forecast prepared by Pike Research indicate that the compound annual growth rate (CAGR) for EV sales will reach 19.5 percent between 2011 and 2017. By contrast, the CAGR for all vehicles will be 3.7 percent over the same time period. Even with the robust growth forecast by Pike, the report predicts that the U.S. will fall far short of President Obama's goal of 1 million advanced technology vehicles in the U.S. by 2015.[245]

Recent PEV forecasts demonstrate a significant degree of uncertainty with respect to near- and mid-term market penetration. In a recent article discussing market uncertainty, Greentech Media

---

[240] Greene D and Z Lin. 2010. "A Plug-in Hybrid Consumer Choice Model with Detailed Market Segmentation." In *Proceedings of the Transportation Research Board 89th Annual Meeting*, January 10–14, 2010, Washington, D.C.

[241] Becker TA and I Sidhu. 2009. *Electric Vehicles in the United States: A New Model with Forecasts to 2030*. 2009.1.v.2.0, Center for Entrepreneurship and Technology, University of California, Berkeley. Accessed October 22, 2010 at http://www.odpowiedzialnybiznes.pl/public/files/CET_Technical%20Brief_EconomicModel2030.pdf (undated webpage).

[242] EIA 2012a.

[243] O'Dell J. 2010a. *Deloitte Study Sees EV Growth Hampered by Battery Costs, But Rising After 2015*. Edmunds Auto Observer. Accessed June 25, 2012 at http://www.autoobserver.com/2010/05/deloitte-study-sees-ev-growth-hampered-by-battery-costs-but-rising-after-2015.html (undated webpage).

[244] O'Dell J. 2010b. *Formidable Roadblocks Remain to Broad Acceptance of Electric-Drive Vehicles; Report by J.D. Power & Associates Says Growth Prospects May be 'Over-Hyped'*. Edmunds Auto Observer. Accessed June 26, 2012 at http://www.autoobserver.com/2010/10/formidable-roadblocks-remain-to-broad-acceptance-of-electric-drive-vehicles-report-by-jd-power--associates-says-growth-prospects-may-be-over-hyped.html (undated webpage).

[245] Hurst D and J Gartner. 2011. *Executive Summary: Electric Vehicle Market Forecasts: Global Forecasts for Light-Duty Hybrid, Plug-in Hybrid, and Battery Electric Vehicles: 2011-2017*. Pike Research LLC, Boulder, Colorado. Accessed June 20, 2012 at https://www.pikeresearch.com/wordpress/wp-content/uploads/2011/08/EVMF-11-Executive-Summary.pdf (undated webpage).

Research highlighted 2020 PEV forecasts ranging from 2 percent (Goldman Sachs) to 14 percent (International Energy Agency) of the world market. For the U.S. market, the report highlighted 2020 PEV market penetration forecasts prepared by the California Air Resources Board (5 percent), Deutsche Bank (7 percent), and Roland Berger (13 percent).[246]

The forecasts in Balducci (2008), Sullivan et al. (2009), DOE (2012a), and EPRI/NRDC (2007) were designed with scenarios based on increasingly aggressive assumptions. Some of these scenarios assume that the PHEV will ultimately become the dominant alternative-fuel vehicle. The EPRI/NRDC study was focused on the potential environmental impact of PHEV market penetration. Therefore, aggressive assumptions were required under some of the scenarios to generate a reasonably significant and measurable environmental impact. These studies do not present the scenarios as definitive or assign probabilities to their outcomes. Rather, the studies are designed to measure the effect or estimate the penetration rate, given certain sets of assumptions. If the goals outlined in these studies are not reached, market penetration rates would certainly be lower than estimated. EIA estimates are generated by the National Energy Modeling System (NEMS), which does not use aggressive assumptions to determine the market potential of PEVs. Instead, the light-duty alternative-fuel vehicle market is forecast by NEMS to be dominated by diesel, flex-fuel, and hybrid electric vehicles, not PEVs.

#### A.8.3.1 Associated Stakeholders

Historically, the vast majority of all EVs have been marketed to public agencies and private companies. Thus, sales to private citizens have been negligible. In 2009, 95.4 percent of all EVs in use were owned by private companies and municipal governments.[247] An additional 3.5 percent were owned and operated by state agencies. The remaining 1.1 percent were operated by federal agencies, electric utilities, natural gas companies, and transit agencies. In addition to the fleet operators identified above, stakeholders in the PEV market space include:

- end users – Those who own PEVs need straightforward and safe ways to charge their vehicles and be provided with incentives and technology that encourage off-peak charging so that distribution and system-capacity constraints are accommodated.
- electric-service retailers – This group needs to provide consumers with reasonable programs for accommodating PEVs. They need to coordinate the constraints on the generation and delivery of electricity and have incentives from the delivery and wholesale-power stakeholders to enhance the efficient use of electric resources. Metering and communication mechanisms need to be deployed to meet the needs of the energy products offered.
- distribution-service providers – The planning and operations of the electricity distribution system need to manage the peaks in PEV consumption so capacity constraints are not violated. More distribution system assets will be needed if PEVs do not apply load management strategies. With load management technologies and the appropriate incentives for off-peak charging, higher asset utilization can be reached, thus reducing the potential need to increase electricity rates.

---

[246] Hofstetter D. 2011. *All Your Forecasts are Wrong: How Many EVs Will Be On the Road by 2015?* Accessed June 17, 2012 at http://www.greentechmedia.com/articles/read/does-it-matter-how-many-evs-will-be-on-the-road-by-2015/ (undated webpage).

[247] EIA – U.S. Energy Information Administration. 2012b. "Estimated Number of Electric Vehicles in Use, by State and User Group, 2009." *Alternatives to Traditional Transportation Fuels 2009*, Independent Statistics & Analysis, Washington, D.C. Accessed June 26, 2012 at http://www.eia.gov/renewable/afv/archive/index.cfm (undated webpage).

- transmission providers – As PEV penetration increases, the bulk power grid may potentially need some investment as well. Unlike in the distribution system, the load impacts from PEVs are more diversified, and with load control strategies should not contribute significantly toward the system peak.
- balancing authorities – Charging systems developed with the ability to schedule and respond to emergency system situations can provide new, fast-acting resources to system operators. The demand side, with high penetrations of PEVs, can provide system reserve and balancing resources if equipped with communications and control technologies.
- generation and demand wholesale market operators – PEVs whose charging can be scheduled and respond to grid conditions can be aggregated at the wholesale level to provide competition with other generation and demand resources. Market trading products need to be reviewed as penetration levels become significant. The estimation of the resource availability is challenging because of the uncertainties of the resource mobility.
- automotive manufacturers – Automotive manufacturers have increasingly acknowledged the market feasibility of PEVs. Federal OEM subsidies and tax incentives have encouraged the development of PEVs by improving the value proposition and return on investment for electric-drive vehicle purchases.
- products and services suppliers – This represents a new market area for suppliers. Battery manufacturers, home energy management systems manufacturers, EV charging station manufacturers, advanced meter manufacturers, and auto manufacturers are just some of the stakeholders who will look to develop business plans in this area.
- policy makers and advocates – Policy decisions are needed for funding PEV research and development programs, designing tax incentives, and establishing the regulatory framework in which the other stakeholders operate. System reliability and cybersecurity issues become heightened concerns as greater penetration levels are realized. Policy advocates would also include environmental groups focused on reducing emissions through accelerated PEV adoption.
- standards organizations – A community of stakeholders from the automotive, power, electrical, mechanical, and software engineering communities needs to coordinate activities to initiate work on standards that will support the physical and information networking integration of PEVs with the electricity infrastructure. Building code regulatory authorities are working toward a national model code for municipalities and other regional and local regulatory authorities to adopt building codes to make future single- and multi-family dwellings PEV ready.
- financial community – Venture capital and investment firms will be important players for providing the capital to fund entrepreneurial and regulated electricity service provider infrastructure efforts needed to support growth in this area.

#### A.8.3.2 Regional Influences

In 2009, the five states with the greatest number of PEVs operating on-road were California (55.2 percent of the U.S. total), New York (12.8 percent), Arizona (8.3 percent), Michigan (3.3 percent), and Massachusetts (3.1 percent). The large share of PEVs operated in California reflects the state's commitment to improving air quality through the adoption of a number of standards and programs, such as the Zero Emission Vehicle Program, designed to reduce vehicle emissions.

Regional differences in market penetration depend in part on state policies that affect the cost of owning and operating PEVs. Figure A.22 identifies states with PEV tax incentives currently in place. Since the 2010 Smart Grid System Report was completed, certain tax incentives have been phased out in several states, including Oregon and California, while new incentives have been added in Maryland, Michigan, Rhode Island, Tennessee, West Virginia, and the District of Columbia. Current tax incentives take many forms:

- an alternative-fuel vehicle tax credit in Georgia equal to 10 percent of the vehicle price up to $2,500
- exemption from state motor vehicle sales and use taxes in Washington
- the State of Utah's income tax credit of 35 percent of the vehicle price up to $2,500
- a tax credit of $75 in Arizona for the installation of a PEV charging outlet
- an alternative-fuel vehicle tax credit of up to $6,000 per vehicle in Colorado.

As shown, incentives are provided throughout much of the western United States and the Southeast. Tax incentives are less prevalent in the Northeast and Midwest.

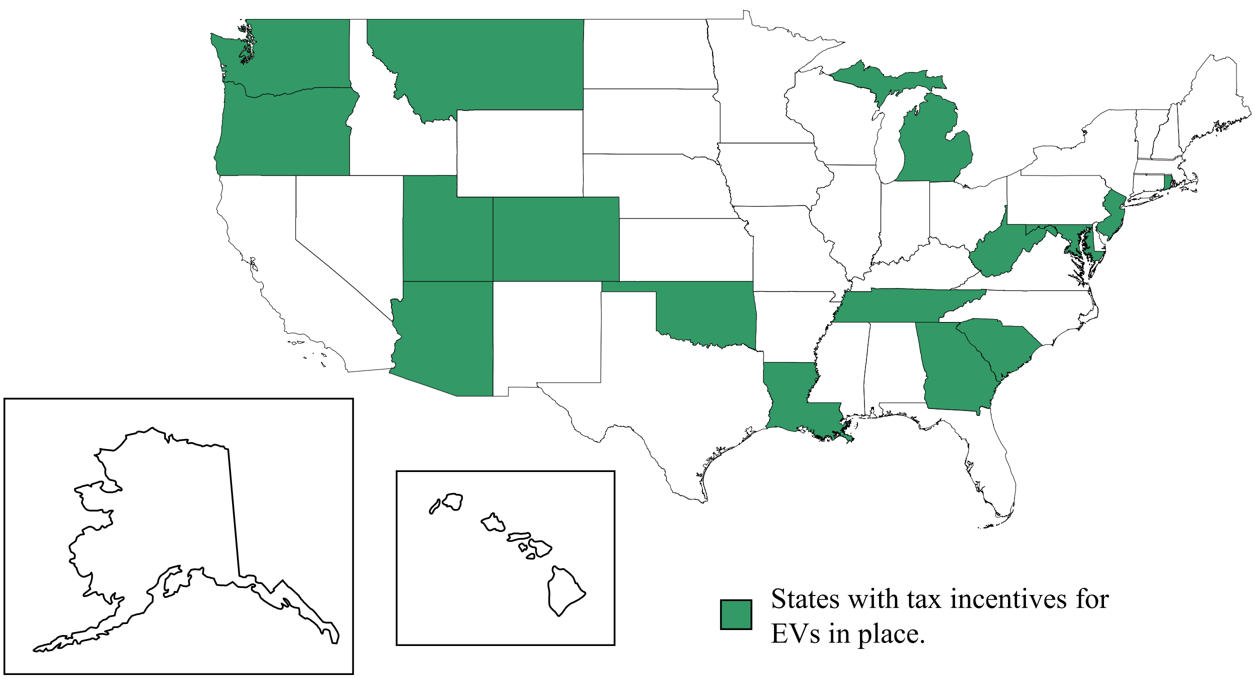



**Figure A.22**. State Tax Incentives for Electric Vehicles

The market success of PEVs is also influenced by regional differences in the prices of electricity and motor fuel. As retail prices for electricity increase relative to the price of gasoline, demand for EVs and PHEVs would be expected to decline. The average retail price per kilowatt-hour by state can be reviewed at the DOE's EIA website at http://205.254.135.7/electricity/sales_revenue_price/.

The availability of idle electric capacity is also a regional issue. A study conducted for DOE by PNNL found that electric infrastructure in the U.S. could support the conversion of up to 73 percent of the light-duty-vehicle fleet to PHEVs without adding more generation and transmission capacity. This figure represents the technical potential and would require strategies for perfect valley-filling of the daily load profile. The availability of electricity in off-peak periods differed by region, with less power available in the Northwest Power Pool Area (10 percent) and the California and Southern Nevada Area (15 percent), and more power available in the Electric Reliability Council of Texas Area (100 percent), Mid-Continent Area Power Pool Area (105 percent), Southwest Power Pool Area (127 percent), and the area covered by the East Central Area Reliability Coordinating Agreement (104 percent).[248]

The availability of charging infrastructure also differs by region. The 2001 National Household Travel Survey found that the majority of trips taken in the U.S. are less than 32 miles.[249] The updated 2009 National Household Travel Survey shows similar results. For those typical trips, standard 120V (Level 1) home charging is sufficient if vehicles return every night to their home. For longer duration trips, however, charging infrastructure is required.[250] The presence of public charging stations (Level 2 and Level 3) facilitates the operation of EVs and encourages their adoption. Thus, states that invest more heavily in EV infrastructure ultimately encourage EV market penetration. Figure A.23 identifies the number of EV charging stations located in each state. As shown, there are roughly 1,000 public charging stations in California, more than any other state in the nation. Other states with more than 500 public charging stations include Tennessee, Michigan, Oregon, Florida, Washington, and Texas.

[248] Kintner-Meyer M, K Schneider, and R Pratt. 2007. "Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids, Part I: Technical Analysis." In *Electric Utilities Environmental Conference, the 10th Annual EUEC Conference and Expo. Clean Air, Mercury, Global Warming and Renewable Energy*, Vol 1. January 22-24, 2007, Tucson, Arizona.

[249] DOT – U.S. Department of Transportation. 2003. *Highlights of the 2001 National Household Travel Survey*. BTS03-05, Table A-8, Bureau of Transportation Statistics, Washington D.C.

[250] Johnson J, M Chowdhury, Y He, and J Taiber. 2012. *Facilitating the Battery Charging Process in Electric Vehicles through Connected Vehicle and Infrastructure*. Presented at the 2012 Transportation Research Board Annual Meeting, Washington, D.C.

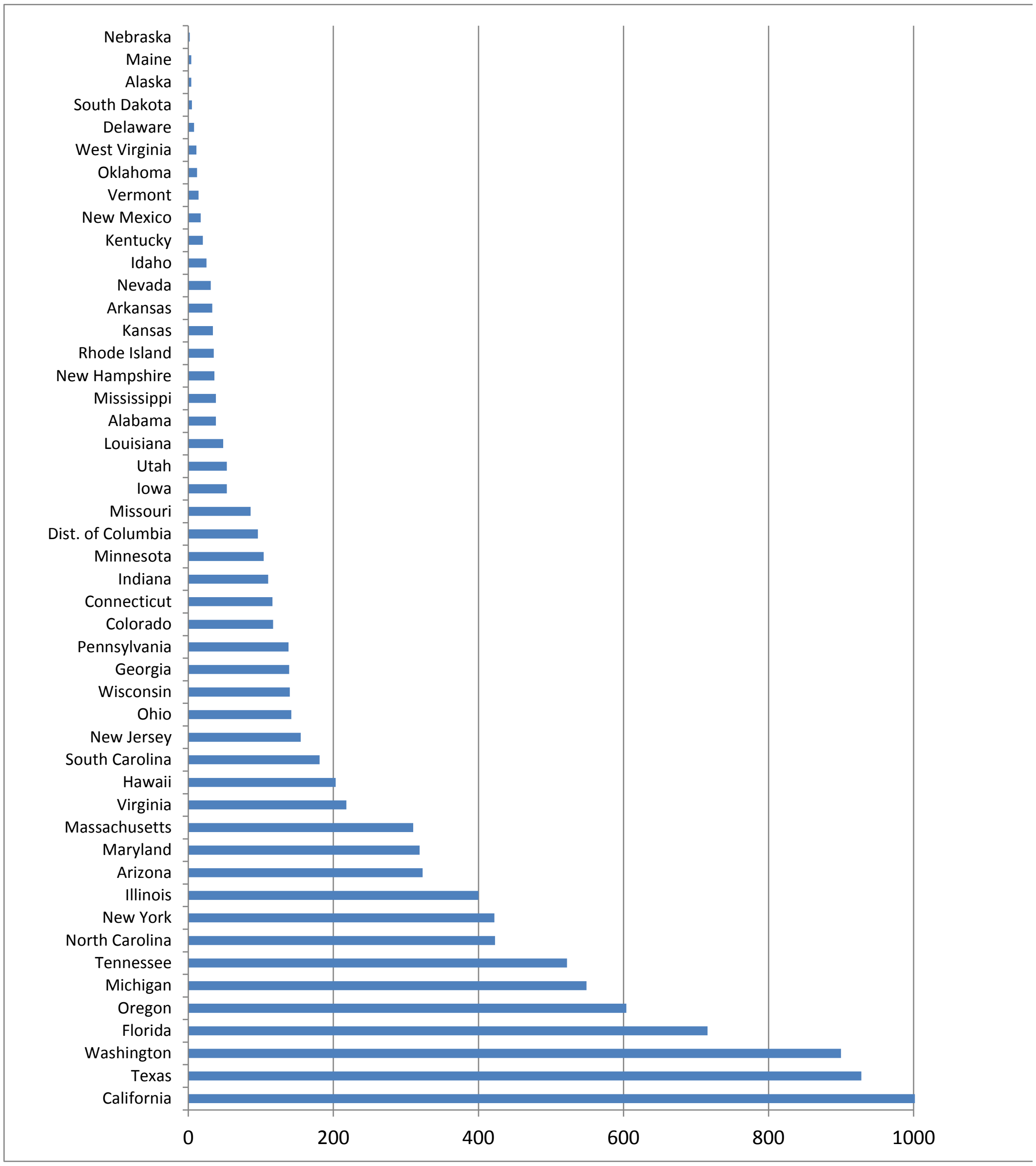



**Figure A.23**. Electric Vehicle Public Charging Station Count by State[251]

## A.8.4 Challenges to Deployment

Market penetration generally follows along a logistic-function, or S-shaped, curve. The market penetration curve would include a period leading up to the introduction of commercially viable PEVs; early stages of commercialization, with an evolving technology and new battery and automotive manufacturing facilities being brought on line; ramp-up of production with a mature technology and a significant expansion in the capacity to manufacture and distribute PEVs; and finally, full market potential being reached within relevant market constraints. At each stage in the development process there will be technical and financial barriers that must be addressed. These barriers are discussed below.

[251] DOE 2012b.

### A.8.4.1 Technical Challenges

Technical barriers related to battery technologies; the automotive manufacturing process; supply-chain, refueling and range limitations; and electricity-infrastructure capacity include the following:

- Battery technology limitations include energy intensity, durability, battery life, battery safety aspects, battery size and weight, the cost to manufacture the batteries required to power PEVs, and raw-material constraints.
- Automotive manufacturing process limitations include incorporation of the weight and space demands of the battery systems; design of instruments to monitor the charge and temperature of the battery system; a graphical user interface to communicate relevant battery information to the driver; incorporation of blowers, pumps and other elements into the design process; building of the battery system into the manufacturing process; retooling of plants; and maintenance of vehicle safety.
- Supply chains include the entities required to get a product or service from the supplier to the consumer. They need to evolve in order to build suppliers of everything from power electronics to high-power circuit boards. A battery-recycling industry and processes need to be developed. Battery testing facilities need to be expanded to test new battery systems. New safety and maintenance procedures need to be developed and communicated to the automotive service industry and first responders.
- The limited ability to refuel while traveling and significant limitations in the range of all-electric vehicles limit market penetration. While this challenge continues today, EV charging stations are being installed across the U.S. and, by 2015, Pike Research estimates that nearly 1 million charging stations will be in place in the U.S., with 4.7 million available worldwide.[252]
- Approximately one-third of all light-duty vehicles park in the street with very limited or no access to a 120 V or 240 V power supply. Infrastructure would need to be developed to provide access to recharging outlets for those customers who live in high-density apartment and condominium complexes.
- Load management technologies are required to minimize the impact that millions of PEVs would have on electricity infrastructure. Advanced communication and control technologies coupled with financial incentives for charging with off-peak power could not only manage the load but could turn PEVs into a grid asset capable of providing ancillary services (e.g., load following, voltage control). The need for these ancillary services is expected to grow as the U.S. integrates variable generation wind and solar power.

### A.8.4.2 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- The top consumer concerns about HEVs are insufficient power (34 percent), price (27 percent), and vehicle dependability (24 percent).[253] These concerns would transfer to the PEV marketplace.
- There are driver profiles that do not favor PEVs (e.g., heavy use on highways, long commutes, transport of heavy loads).

[252] Pike Research. 2010. *Electric Vehicle Charging Equipment.* Boulder, Colorado.
[253] Greene et al. 2004.

- A recent consumer survey published by EPRI cited range expectations and the potential for emergency situations to require extended driving as significant concerns to consumers.[254]
- The recharging process is not viewed as convenient by some consumers. PEVs require a new way of refueling a personal vehicle, with respect to both frequency and duration.
- If the load associated with PEV charging is not properly managed, electricity rates could increase as a result of infrastructure upgrades required to address the additional strain placed on the grid. Such a development would widen the cost gap between PEVs and ICE vehicles.

The aforementioned business and financial challenges translate into costs to consumers. Since consumers generally require short payback periods, the marginal costs associated with PEVs today result in a payback period that is unacceptable to most customers.

### A.8.5 Metric Recommendations

Because PEVs are receiving increasing attention among industry experts, alternative forecasts of PEV market penetration have been presented from several sources. These forecasts, however, vary significantly in their underlying assumptions, methods, and findings. As additional studies are completed and PEVs are introduced into the marketplace, these forecasts should become more unified. These studies should be identified and compared against the forecasts built into the U.S. Department of Energy's *Annual Energy Outlook*. Some analysis of these alternative forecasts should be performed in order to determine the most likely market penetration trajectory.

In addition to tracking market penetration, the research team might also consider tracking PEV grid impacts, in terms of total annual electric energy demand in megawatt-hours but also in terms of charging profiles (hourly load profiles) for various rate structures or other incentive programs. Also, the number of public charging stations could be an option as a metric.

[254] EPRI – Electric Power Research Institute. 2011. *Southern Company Electric Vehicle Survey: Consumer Expectations for Electric Vehicles.* Palo Alto, California.

## A.9 Metric #9: Non-Generating Demand-Response Equipment

### A.9.1 Introduction and Background

This metric measures the penetration of demand-side equipment that is responsive to the dynamic needs of the smart grid. The products that have emerged and continue to evolve in this category either directly monitor the system or receive communicated recommendations from the smart grid. This equipment then provides dynamic responses useful to system needs either through automated responses or through the conveyance of useful information to consumers who then might respond appropriately. This metric includes only those grid-responsive features that are available on original equipment or by the simple retrofit of existing equipment without needing highly skilled labor. This metric intentionally excludes advanced meters (to be addressed in Metric 12), communications gateways (e.g., home management systems, building automation systems), equipment that generates or stores electrical energy, and equipment that requires unique engineering for its installation at an endpoint. This excludes much industrial and commercial equipment, except those examples having dynamic grid responses that are supplied on original equipment or by simple retrofit. The metric excludes many "smart" equipment features that target conservation (e.g., occupancy sensors, dirt sensors) or non-energy purposes (e.g., entertainment, security, health).

Examples of grid-responsive equipment include communicating thermostats, responsive appliances, responsive space conditioning equipment, consumer energy monitors, responsive lighting controls, and controllable wall switches. This category of equipment also encompasses switches, controllable power outlets and various other controllers that could be used to retrofit or otherwise enable existing equipment to respond to smart-grid conditions. For example, a new "smart" refrigerator may be equipped with a device that coordinates with an energy management system to adjust temperature controls, within user-specified limits, based on energy prices. Perhaps a new "smart" surge protector or power strip would communicate with the facility's energy management system on behalf of the appliances plugged into it. An energy "orb" could advise owners of energy price penalties and opportunities to run appliances when prices are low.[255] Consumers whose equipment connects to the Internet might remotely receive updates on equipment status and energy prices, and be informed of maintenance issues by e-mail or another message service. These devices may also have device settings remotely controlled over the Internet. The examples are numerous. Doubtlessly, more will be invented.

The technology exists to implement such grid-responsive equipment. However, there is little standardized supporting infrastructure to communicate with the equipment, nor is there significant demand for it yet. Only 8.7 percent of all meters have the capability to allow some form of time-based or incentive-based price structure. Even fewer customers have the ability to take advantage of the

---

[255] There are at present at least two kinds of orb designed to indicate the present and anticipated cost of power. For example, this site http://inhabitat.com/the-energy-orb-monitor-your-electricity-bill/ attributes the invention to Southern California Edison. Another device seen at http://www.earthtechling.com/2012/02/companies-create-low-cost-energy-meter/ describes a device from MIT's media lab. Ambient also has an orb technology, which is discussed at http://www.prnewswire.com/news-releases/pacific-gas-and-electric-companys-energy-orb-alerts-businesses-when-conservation-is-needed-to-prevent-power-shortages-56376942.html.

equipment, as only a small fraction of utilities have programs for time-based or incentive-based pricing.[256] Figure A.24 indicates the appliance demand on electricity loads of a representative residence, with those identifiable appliance loads highlighted, and whose curtailment can make significant reductions in demand when the grid realizes a frequency disturbance.

ARRA co-funded 30 projects that purchase and install programmable communicating thermostats as well as other demand response equipment, including smart appliances and load controllers for water heaters and air conditioners. As of September 30, 2012, 186,687 programmable communicating thermostats and 282,571 direct load control devices had been deployed under the SGIG and SGPD combined.[257,258]

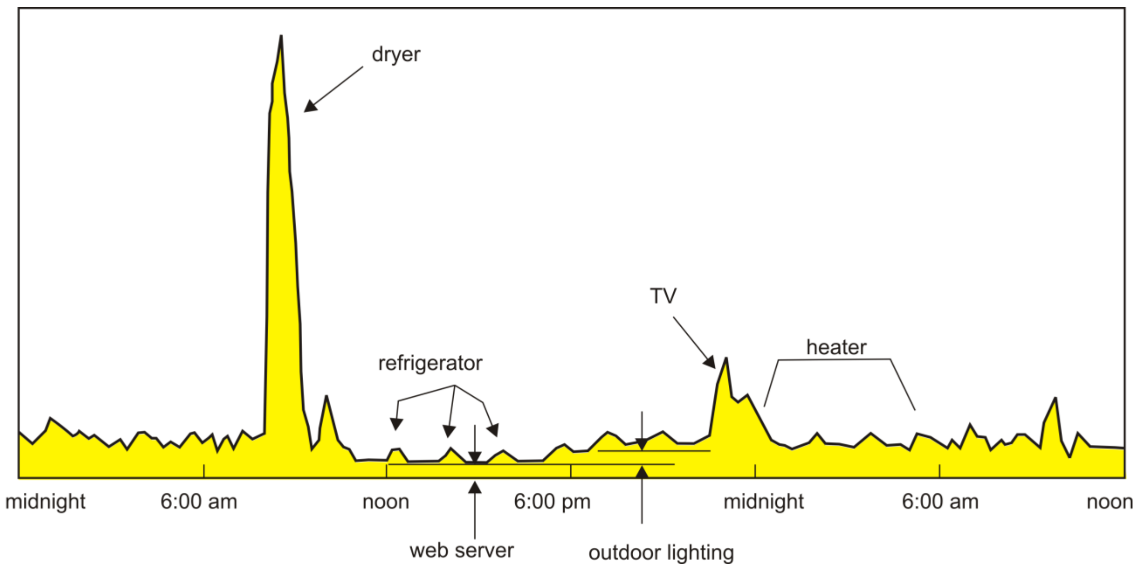



**Figure A.24**. Residential Energy Demand with Appliance Demand Indicated[259]

## A.9.2 Description of Metric and Measurable Elements

This metric tracks the effectiveness and penetration of grid-responsive, non-generating demand-side equipment. The distinction from Metric 5, "Load Participation," is that this metric focuses on the original equipment that is equipped to be grid-responsive, while Metric 5 addresses benefits achieved from all controllable loads. The following two measurements have been identified as important to understanding and quantifying grid-responsive, non-generating demand-side equipment.

*(Metric 9.a) Total U.S. load capacity in each consumer category (i.e., residential, commercial, and industrial) that is actually or potentially modified by behaviors of smart, grid-responsive equipment*

---

[256] FERC – Federal Energy Regulatory Commission. February 2011. *2010 Assessment of Demand Response and Advanced Metering*. Staff Report, Docket Number AD-06-2-000, Washington, D.C. Accessed June 14, 2012 at http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf.

[257] DOE – U.S. Department of Energy. 2012. Recovery Act Smart Grid Programs. SmartGrid.gov, Washington, D.C. Accessed November 28, 2012, at http://www.smartgrid.gov/ (undated web page).

[258] Wang, W. 2013. Personal Communication. Data Compiled from ARRA Recipient's Federal Financial Reports (FFR) SF-435. May 31, 2013.

[259] Adapted from Chu S. September 2009. *Investing in Our Energy Future*. U.S. Department of Energy, Washington, D.C. Accessed February 7, 2012 at http://www.storagealliance.org/sites/default/files/whystorage/Steve-Chu-4774.pdf.

*(MW).* Tracking the influence of new and enhanced "smart" consumer equipment differentiated between residential, commercial, and industrial types defines this metric.

*(Metric 9.b) Total yearly U.S. retail sales volume for purchases of smart, grid-responsive equipment ($).* Establishing an overall market-share baseline for these devices will allow analysts to chart device penetration and commercialization success.

### A.9.3 Deployment Trends and Projections

The FERC's *2010 Assessment of Demand Response and Advanced Metering*[260] estimated that demand response grew to 58 gigawatts (GW) from the 2008 assessment of 37 GW. Penetration of advanced meters reached 8.7 percent. The number of customers on time-of-use rates declined from the previous survey to 1.1 million customers, down about 180 thousand customers. Only 19 entities reported real-time pricing, down significantly from the previous survey.

Without two-way communication and utility demand response programs in which appliances and equipment can respond to pricing, the value of "smart" appliances will not be realized. In their Assessment, FERC did note that programs that take advantage of smart meters (such as real-time pricing, peak-time rebate and critical peak pricing) are increasing over time. The number of such programs planned is set to increase from 79 in 2010 to 120 in 2015, with the peak-load reduction potential increasing from 2,896 megawatts (MW) to 3,670 MW over the same period.

While useful, peak-load reduction potential does not represent the values for this metric. First, the smart equipment tracked by this metric could offer features other than traditional demand response. For example, a price-alert signal on a dryer would probably qualify the equipment as smart and responsive to the needs of the grid, but it does not necessarily bring about direct demand response, i.e., the customer does not necessary respond to the signal. In addition, this metric is not exclusively focused on automated grid response and includes equipment that is directly operated by consumers. In addition, the FERC numbers reported above also include scheduled voluntary responses (especially for industrial programs) that are communicated by phone or e-mail and do not necessarily use or require any automation or smart equipment.

Programmable, communicating thermostats are a near-term success story in this equipment category. Numerous installations of communicating thermostats have been conducted at pilot scale, and full implementations are under way. The California Energy Commission had planned to require programmable communicating thermostats as part of its 2008 update to the Building Energy Efficiency Standards, but had to revise this requirement.[261] A recent CleanTech report indicated that Honeywell, Inc. had already installed 950,000 thermostatic load control devices, while Carrier Corp. had installed 80,000 two-way communicating thermostats.[262] Austin Energy will have installed 86,000 smart

---

[260] FERC 2011.

[261] CEC – California Energy Commission. 2008. *California's Energy Efficiency Standards for Residential and Nonresidential Buildings.* Accessed May 16, 2012 at http://www.energy.ca.gov/2008publications/CEC-400-2008-001/CEC-400-2008-001-CMF.PDF. Last updated January 1, 2010.

[262] Neichin G, D Cheng, S Haji, J Gould, D Mukerji, and D Hague. 2010. *2010 U.S. Smart Grid Vendor Ecosystem: Report on the companies and market dynamics shaping the current U.S. smart grid landscape*. The Cleantech Group. Accessed May 17, 2012 at: http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/2010_U.S._Smart_Grid_Vendor_Ecosystem_Report.pdf.

thermostats by the end of 2012 as part of its broader "Pecan Street Project."[263] Since approximately 45 percent of residential demand is associated with heating and cooling, devices to control the timing of heating and cooling could significantly shave peak demand.[264]

Unlike the situation with thermostats, appliances that are grid responsive remain in their commercialization infancy. Trials have occurred in small pilot-scale installations only, where, in most cases, only limited integration of the grid-responsive features has been achieved. The Pacific Northwest Gridwise™ Testbed used two projects to demonstrate grid-friendly appliances, water heaters and thermostats. In the first, the Olympic Peninsula Project, a real-time market for electricity prices was matched with 50 clothes dryers [10 kilowatts (kW)], residential water heaters (~75 kW) and thermostats. In the other Gridwise Testbed project, the Grid Friendly™ Appliance project, 50 water heaters (40 kW) and 150 clothes dryers (30 kW) were installed.[265] The results were promising. In a more recent project, Grid Friendly appliances reduced load fluctuations and decreased peak loads and consumer energy costs.[266]

There are a few other examples. Since 2002, using gateway technology pioneered by Microsoft and Salton, Inc., Westinghouse has manufactured appliances such as bread machines and coffee makers that communicate with each other through an alarm-clock-like gateway that synchronizes its schedule and those of similar devices via the Internet.[267]

Smart appliances were demonstrated at the Consumer Electronics Show in Las Vegas during 2012. Samsung and LG Electronics demonstrated appliances that could connect to the smart grid; these two appliances, however, were more about convenience than controlling the load in your house. LG Electronics' refrigerator, communicating with a smart phone, could tell its owner what groceries to buy on the way home, while Samsung's clothes washer informed the user that its cycle was completed.[268] Conceivably, these communicating appliances could respond to energy objectives, although they are promoted for consumer convenience and other non-energy objectives. Other manufacturers are developing and testing responsive appliances, too.

Retrofit-able lighting controls have existed for years. Eaton has developed a home energy management system with smart circuit breakers. The system can turn systems on and off either at preset times or in response to electricity pricing signals.[269] Wirelessly addressable and dimmable fluorescent

---

[263] Carvalo A. 2012. *LightsOn: Austin Energy Delivers First Smart Grid in the US.* Accessed May 17, 2012 at http://www.electricenergyonline.com/show_article.php?mag=60&article=451.

[264] Neichin et al. 2010.

[265] Hammerstrom D. February 2010. *The Pacific Northwest GridWise® Testbed Demonstration*. PNNL-SA-70641, Pacific Northwest National Laboratory, Richland, Washington. Accessed May 15, 2012 at https://www.smartgrid.gov/sites/default/files/doc/files/PNNL_GridWise_Testbed_Demo_Projects_Part_I_Olympic_Peninsula_200711.pdf.

[266] Battelle Memorial Institute. 2012. *Pacific Northwest Smart Grid Demonstration Project 2011 Annual Report.* Accessed May 16, 2012 at http://www.pnwsmartgrid.org/docs/2011_annual_report.pdf.

[267] Business Wire. April 22, 2002. *Salton, Inc. Introduces 'Smart' Home Appliances Under the Westinghouse Brand Powered by Microsoft*. Accessed May 16, 2012 at http://www.thefreelibrary.com/Salton,+Inc.+Introduces+%22Smart%22+Home+Appliances+Under+the...-a084961157.

[268] Castle S. January 2012. *2012 the Year of Smart Appliances?* GreenTech Advocates. Accessed May 10, 2012 at http://greentechadvocates.com/2012/01/19/2012-the-year-of-smart-appliances/.

[269] Castle S. September 2011. *Eaton's Smart Energy Management Could be a Mid-Market Winner*. GreenTech Advocates. Accessed May 17, 2012 at http://greentechadvocates.com/2011/09/14/eaton%E2%80%99s-smart-energy-management-could-be-a-mid-market-winner/

fixtures have become available for daylight adjustments and for commercial-building demand response.[270,271]

Autonomously responding equipment is also in its infancy, though more manufacturers are exploring smart-grid responsive designs. There are several examples:

- General Electric introduced their first "smart" water heaters, while smart-grid responsive models of other appliances remain in utility demonstration projects.[272]
- Some large commercial air handlers have been installed with under-frequency or under-voltage responses.[273]
- Frequency responsiveness has also been installed via load-control modules (not necessarily fitting our equipment category) on refrigerators in the United Kingdom, to provide dynamic demand control.[274]
- Hawaiian Electric (HECO) is set to do pilot testing of a fast demand-response system using Honeywell's Tridium and Akuacom technologies. In the second phase of that project, automated demand response will reduce demand if renewable energy supplies dwindle by automatically reducing air conditioning, nonessential lights, pumps and motors. The goal is to shed 6 MW of energy when required and provide information on the changing load back to the utility every 5 minutes.[275]
- General Electric, in conjunction with Reliant, Louisville Gas & Electric (LG&E) and the Vineyard Electric project, have been cooperating in a pilot test of a line of appliances that are smart-grid enabled in live environments in Texas, Kentucky and Massachusetts. The project's goal is to demonstrate how a typical family might make use of smart-grid connected washing machines, dryers, and refrigerators to manage their home energy use. The LG&E pilot has been demonstrating price responsiveness and end-users have noted they can save up to 20 percent on their utility bills.[276]

Many residential and commercial aggregators already incorporate web-page information services to utilities and customers as part of their system:

---

[270] Lockheed Martin Aspen. 2006. *Demand Response Enabling Technologies for Small-Medium Businesses*. Submitted to Southern California Edison, Rosemead, California. Accessed May 17, 2012 at http://sites.energetics.com/MADRI/pdfs/LMADRT_060506.pdf.

[271] Piette MA, S Kiliccote, and G Ghatikar. 2008. *Linking Continuous Energy Management and Open Automated Demand Response*. In Proceedings of *Grid-Interop Forum 2008*, November 11-13, 2008, Atlanta, Georgia. Accessed May 17, 2012 at http://openadr.lbl.gov/pdf/1361e.pdf.

[272] Smith R. *New Appliances, in Sync with Meters, Shift to Energy-Saver Modes When Told*. The Wall Street Journal, Online. Accessed May 17, 2012. Available at http://online.wsj.com/article/SB125409532770645001.html.

[273] Hammerstrom DJ, J Brous, DP Chassin, GR Horst, R Kajfasz, P Michie, T Oliver, TA Carlon, C Eustis, OM Järvegren, W Marek, RL Munson, and RG Pratt. 2007. *Pacific Northwest GridWise™ Testbed Demonstration Projects: Part II. Grid Friendly™ Appliance Project.* PNNL-17079, Pacific Northwest National Laboratory, Richland, Washington. Access May 17, 2012 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17079.pdf.

[274] dynamicDemand. No date. *Frequently Asked Questions: How do we know the effects on the grid?*. Accessed May 17, 2012 at http://www.dynamicdemand.co.uk/faq.htm

[275] The Smart Grid Observer. February 2012. *Honeywell and Hawaiian Electric to Collaborate on Demand Response Pilot*. Accessed May 17, 2012 at http://www.smartgridobserver.com/n2-2-12-2.htm.

[276] ebuild. January 2011. *GE's Energy-Efficient Appliances Just Got Smarter - What a Brillion Idea*. Accessed May 17, 2012 at http://pressroom.geconsumerproducts.com/pr/ge/ge-s-energy-efficient-appliances-190126.aspx

- Ambient Devices' wireless energy orb was demonstrated in conjunction with Pacific Gas and Electric Company (PG&E). The orb color indicated to customers various dynamic electrical energy price conditions.[277]
- Whirlpool Corporation demonstrated in its Woodridge Study that appliance consumption could be reduced and deferred by appliance panel indicators and customer feedback.[278]

According to recent interviews conducted for this report (see Appendix B),

- 43.3 percent of responding utilities presently have no automated responses for price signals sent to major energy-using equipment, down from the 62.5 percent reported in the 2010 Smart Grid System Report.
- 23.3% have some in development, down from 29.2 percent.
- 33.3% didn't respond to this question.
- None of those reporting indicated such equipment being installed for any number greater than 10 percent of their customers.

Tendril, a home energy management startup, demonstrated their Wi-Fi thermostat along with smart plug and control devices at Grid Interop 2011. The devices were controlled by ZigBee® communication in a smart meter. The system used a prerelease version of Smart Energy 2.0, which allowed communication between ZigBee, Wi-Fi, and HomePlug® technologies. Tendril's system also can communicate with OpenADR, a standard for utilities and vendors. The OpenADR uses Honeywell and Lockheed Martin devices.[279]

In the end, smart meters may not be the only way for smart appliances to communicate with utilities and end-users. Tendril is developing a "Cloud Platform," which they have opened to third parties. Tendril is connecting Whirlpool smart appliances, WaterFurnace International, Inc. geothermal water heaters and Vivint, Inc. home control systems.[280] Due to their recent addition to the market, estimates of current smart and web-enabled equipment, as well as forecasts, are hard to obtain. However, due to the convenience, as well as the energy and cost-savings potential of these devices, demand for such devices is expected to increase as the supporting infrastructure becomes available.

#### A.9.3.1 Associated Stakeholders

Associated stakeholders include:

- end-users: Customers will have interest in incentives to reduce electricity bills as peak-demand electricity prices rise.

---

[277] PR Newswire. May 2008. *Pacific Gas and Electric Company's Energy Orb Alerts Businesses When Conservation Is Needed to Prevent Power Shortages*. Accessed May 17, 2012 at http://www.prnewswire.com/news-releases/pacific-gas-and-electric-companys-energy-orb-alerts-businesses-when-conservation-is-needed-to-prevent-power-shortages-56376942.html.
[278] Horst GR. 2006. *Whirlpool Corporation Woodridge Energy Study and Monitoring Pilot.* Whirlpool Corporation. Accessed June 14, 2012 at http://www.uc-ciee.org/downloads/Woodridge_Final_Report.pdf.
[279] St. John J. 2011. *Grid-Interop 2011: ZigBee, HomePlug and Wi-Fi*. Accessed May 17, 2012 at http://www.greentechmedia.com/articles/read/grid-interop-2011-zigbee-homeplug-and-wi-fi/.
[280] St. John 2011.

- balancing authorities and reliability coordinators: Frequency-responsive devices can greatly benefit the grid during stressed conditions and prevent blackouts.
- product and service providers: They are interested if there is a market. Appliance manufacturers will have an obvious role to play in providing the market with competitive and high-quality "smart" solutions and should welcome an opportunity to compete by providing better grid services than do their competitors. Developers of wireless transmission platforms also have a large stake in determining a standard technology for transmitting data to grid-responsive devices.
- policy makers: The need to create incentives to create a more reliable grid.

#### A.9.3.2 Regional Influences

Smart devices will be expected to meet the same standards that non-smart devices are required to meet in terms of energy use, safety, and other regional parameters.

The evolution of smart-grid devices will be heavily influenced by the way energy programs are offered and enacted. Energy programs tend to be localized and regional; however, smart-grid devices will be most economically manufactured on a national, or even global, scale. Cost-effective application of smart-grid devices will be difficult to attain without much standardization.

The region of the country may influence types of equipment used regionally, because of the different energy mix for each region. Areas where winter peak loads are greater than summer peak loads may face different energy demands and prices than those where the opposite is true. Figure A.25 and Figure A.26 show example average daily residential end-use profiles for January and September, respectively, of a representative 2000-square-foot duplex located in northern Tennessee with standard construction and appliances.[281] Each chart shows consumption values averaged across all days of the month represented. Because of this averaging, the actual daily demand may be understated for once-per-week items such as laundry, while the other items reflect more closely the daily consumption. What the graphics point out is that in this area, heating, ventilation and air conditioning (HVAC) is the primary driver of daily energy consumption. The dryer, if it were run every day, might look similar to the HVAC for its operating period.

[281] Data collected in northern Tennessee by Pacific Northwest National Laboratory.

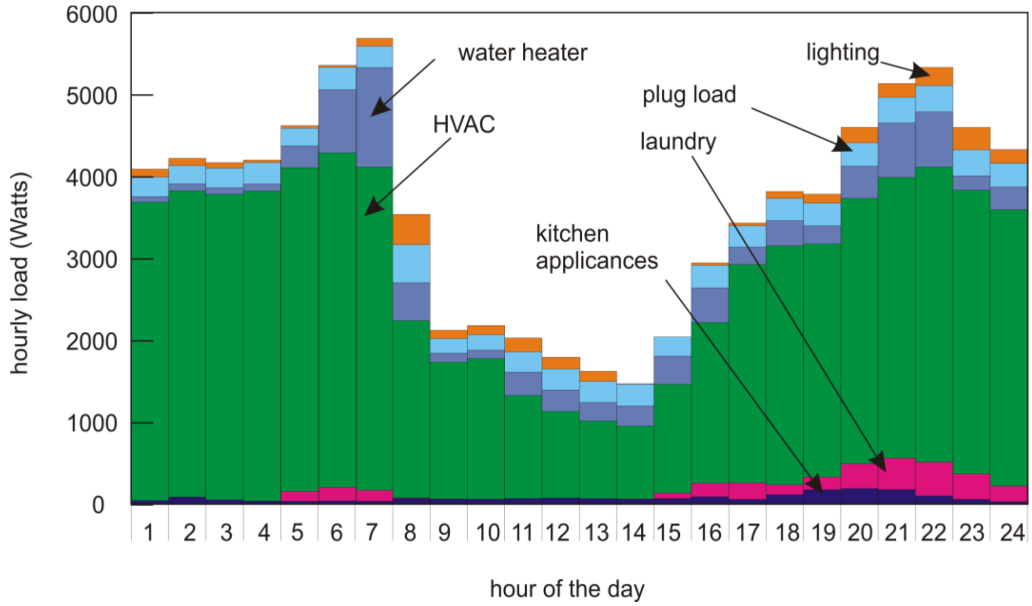



**Figure A.25**. Residential Winter Load Profile for January by Hour (Watts)[282]

Figure A.26 shows the load profile for the same house during September. Note how in this profile the average load is much smaller and does not show the same incentives for peak shaving as Figure A.25 during the winter.

Each area of the country would probably show comparable dissimilarities. Other regional differences that might affect the demand for smart appliances could include the energy supply mix. In areas with abundant natural gas, heating probably would be by gas furnaces rather than electrical appliances. Currently the Northeast heats with distillate fuel oil; thus the profiles would also be different from those depicted in the figures shown here.

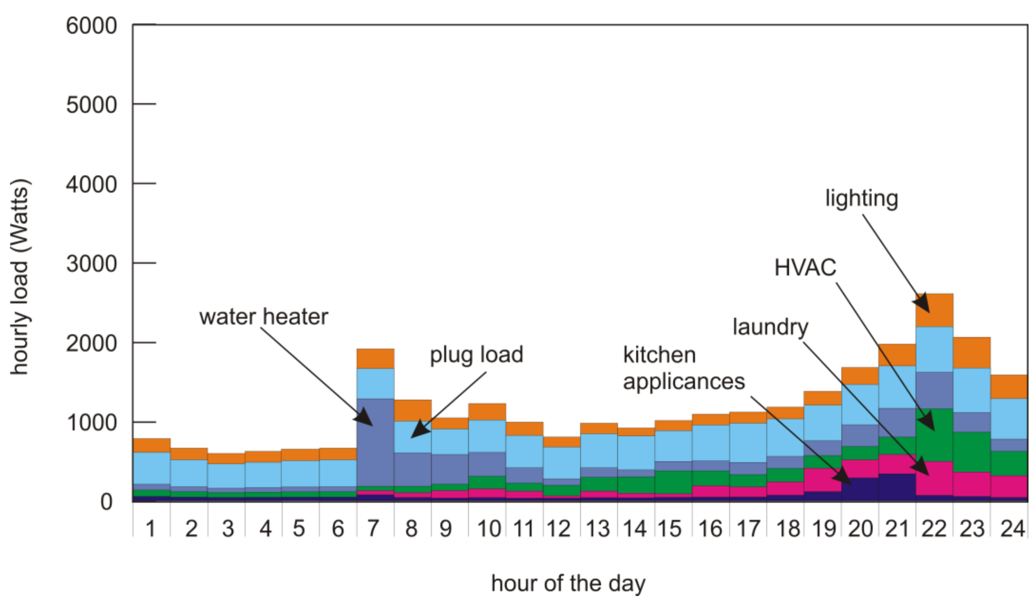



**Figure A.26**. Residential Summer Load Profile for September by Hour (Watts)[283]

[282] Data collected in northern Tennessee by Pacific Northwest National Laboratory.

### A.9.4 Challenges to Deployment

Pike Research has concluded that although the home energy management market has been "stuck in near neutral," that may change as consumers reduce energy consumption through a 'greener mentality.' Such a change could take place as mandated energy efficiency requirements take effect, and as variable electricity pricing becomes more widely available. The real issue is whether consumers will be responsive and whether potential savings can be realized. In addition, a lack of agreed-upon interoperability standards and lackluster support from utilities will continue to hinder non-generating demand-side equipment from becoming a household standard.[284] Nevertheless, it remains to be seen whether the situation will change soon.

#### A.9.4.1 Technical Challenges

Among the biggest challenges facing these devices are technical considerations. Implementing communication interfaces in modern appliances requires significant investments into hardware, software, and firmware design.[285] Memory considerations, such as the amount of data storage, and networking options are important concerns. Other hardware considerations include accommodating diverse operating environments, such as temperature and water exposure.

Further decisions will have to be made regarding communications options. "Wired" networking options have costs and performance characteristics different from those of "wireless" networking options. Even between these two technologies, there is presently little guidance from standards regarding how grid-responsive appliances within the home interface with either each other or control interfaces. Because wirelessly integrated appliances remain a nascent technology, the industry has yet to establish a default interfacing platform among the four leading standards: Wi-Fi, ZigBee, HomePlug, and Z-Wave. For example, Google announced that it was creating its own home networking standard for its Android@Home initiative. Additionally, it will be necessary to increase the ability of whichever platform is used to transmit the volumes of data required for a machine or home network to be responsive to a smart grid.[286] But some type of standard protocol is needed to encourage appliance makers to adopt smart technology.[287]

The American Home Appliance Manufacturers[288] has a similar list of hurdles that communications protocols must overcome:

- While utilities must operate safely and reliably while meeting regulations from multiple sources including federal, state and local groups, FERC has mandated that third parties must be allowed to participate in demand-response markets.

---

[283] Data collected in northern Tennessee by Pacific Northwest National Laboratory.

[284] Pike Research. 2012. *Home Energy Management*. Accessed May 17, 2012 at http://www.pikeresearch.com/research/home-energy-management.

[285] Eren H and E Fadzil. 2007. "Technical Challenges for Wireless Instrument Networks – A Case Study with ZigBee." In Proceedings of *IEEE Sensors Applications Symposium*, February 6-8, 2007, San Diego, California. Accessed May 17, 2012 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=4248502&userType=inst.

[286] Berst J. May 2011. *Will Google destroy ZigBee*. SmartGridNews.com. Accessed May 17, 2012 at http://www.smartgridnews.com/artman/publish/Business_Strategy/Will-Google-destroy-ZigBee-3681.html.

[287] Lahiri S. June 2012. *Wireless connectivity in smart home tech: Zigbee vs Wi-Fi*. EE Herald. Accessed June 15, 2012 at http://www.eeherald.com/section/news/nws201206102.html.

[288] AHAM – Association of Home Appliance Manufacturers. October 2010. *Assessment of Communication Standards for Smart Appliances: The Home Appliance Industry's Technical Evaluation of Communication Protocols*. Washington, D.C. Accessed May 17, 2012 at http://www.smartgridnews.com/artman/uploads/1/AHAM.pdf.

- Physical and electrical variations across consumers impact the deployment.
- Products and services for home energy management utilize many different communication technologies. Lack of a dominant protocol standard may cause interoperability problems.
- Oftentimes appliances move when the owner moves. Without interoperability of the communications standards, the new utility's communication standard may not be the old utility's standard.
- Appliances have long lives, so the standards need to remain backward- and forward-compatible.
- With some appliances residing in basements, protocols need to adapt to the data transmission requirements.

#### A.9.4.2 Business and Financial Challenges

Currently there is significant interest in this field. Businesses such as LG Electronics, Samsung, Whirlpool, General Electric and Westinghouse are designing and producing more "web-enabled" household appliances. Research and development in these fields will poise producers to easily transition into "smart" devices. However, incorporating electronics into increasing numbers of appliances, as well as developing and maintaining software for these appliances, will require a new look at the products' life-cycle costs. A recent report by Pacific Northwest National Laboratory makes the preliminary case that in markets where prices reflect value from load shifting, the benefits outweigh the costs of smart appliances in most instances. Only in California ISO under pessimistic conditions did dishwashers, clothes washers, freezers, and refrigerators *not* show significant net benefits; under optimistic conditions, benefits outweighed costs by two to nine times.[289] Manufacturers and grid entities have not yet settled on standards that would give manufacturers the confidence necessary to fully integrate and launch grid-responsive equipment. Perhaps this is because the business case for integration of these features has not yet been fully proven.

### A.9.5 Metric Recommendations

The smart equipment discussed in this metric remains in its infancy. New examples continue to emerge. Consequently, the definition of which equipment to include in this metric could be revisited in the future. An issue in defining this metric is the emphasis on residential appliances. Commercial building and industrial equipment with embedded, grid-responsive capability deserves to be more closely scrutinized.

Today, the numbers of responsive equipment of other types are overwhelmed by the relative commercial success of one device: the communicating thermostat. This metric could be more meaningful if that device were separated from the rest, leaving a catch-all category for other grid-responsive equipment that is in a much less mature state of commercialization.

Secondary information sources were not readily found for estimating penetration of responsive equipment. More effort is required to accurately quantify the penetration of responsive equipment.

---

[289] Sastry C, R Pratt, V Srivastava, and S Li. December 2010. *Use of Residential Smart Appliances for Peak-Load Shifting and Spinning Reserves: Cost/ Benefit Analysis*. PNNL-19083, Pacific Northwest National Laboratory, Richland, Washington. Accessed May 17, 2012 at http://www.aham.org/ht/a/GetDocumentAction/i/51596.

## A.10 Metric #10: Transmission and Distribution Reliability

### A.10.1 Introduction and Background

The purpose of this metric is to review, quantify, and examine the progress of transmission and distribution (T&D) reliability since the 2010 SGSR was published. "Reliability" in this context means reliability in the same sense as, for example, that of an automobile: how often is it there and operational when you want to use it. This metric is not concerned with reliability in the detailed sense of how often various parts of the system fail. This section examines the reliability of T&D, which is considered a value metric.

We begin by considering the size of the system being examined. In 2008, the General Accounting Office noted that there were over 150,000 miles of transmission lines operating at or above 230 kilovolts (kV). At about the same time, a financial analysis reported 283,000 miles of transmission lines and 2.2 million miles of distribution lines in the United States.[290]

The many owners and operators of these facilities have been the focus of political scrutiny due to a small number of widespread outages, such as the 2003 Northeast power outage and the August 10, 1996, west coast outage. While such events raise the profile of power quality issues, events in the generation and transmission systems account for a small share of all outages. Approximately 92 percent of end-user outages can be traced to problems in the distribution system, most of which are caused by physical damage to the infrastructure.[291] They may be weather- or environment-related, such as tree branches falling on distribution lines, or they may be human-made, such as damage to underground cables caused by digging.

Because there are differences between transmission and distribution systems in terms of technologies, system miles and sophistication, transmission and distribution are generally considered separately, but that separation is sometimes difficult. Whether from transmission or distribution problems, outages may be costly. In 2001, a report from the Electric Power Research Institute estimated power-interruption and power quality cost at $119 billion per year,[292] and a 2004 study from Lawrence Berkeley National Laboratory estimated the cost at $80 billion per year.[293]

One of the biggest policy issues facing utilities and regulators is the provision of adequate capacity. The provision of capacity means the ability to meet the power demand of the load. This is usually a matter of interest at times of peak load. Capacity may involve very little energy since the peak demand

[290] Beach JL and NC Dilts. 2007. *Electric Transmission & Distribution Infrastructure: Powerful Spending Trend Forecast to Extend Well Into the Next Decade.* Stifel, Nicolaus & Company, Incorporated Equity Research, Baltimore, Maryland. Accessed October 22, 2010 at http://classicconnectors.com/downloads/Electric_Transmission_and_Distribution_Infrastructure_Report_Stifel_Nicolaus.pdf (undated webpage).

[291] Gellings C. May 24, 2004. "Behind the Numbers: A Conversation with Clark Gellings, Vice President of Power, Delivery, and Markets at the Electric Power Research Institute." *EnergyPulse™*. Accessed October 22, 2010 at http://www.energypulse.net/centers/article/article_display.cfm?a_id=696 (last updated May 24, 2004).

[292] CEIDS – Consortium for Electric Infrastructure to Support a Digital Society. 2001. *The Cost of Power Disturbances to Industrial & Digital Economy Companies.* Prepared by Primen for the Electric Power Research Institute, Inc., Palo Alto, California. Accessed July 25, 2012 at http://www.onpower.com/pdf/EPRICostOfPowerProblems.pdf. (undated webpage).

[293] Hamachi LaCommare K and JH Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. LBNL-55718, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf (undated webpage).

may be short-lived. The cost of providing capacity is therefore not usually recovered by energy sales, and is regarded as an ancillary service. This particular service often involves moving power across transmission operations areas.

Capacity transfer can cause congestion (overloading) on the transmission system, but can also be dealt with at the end-use (distribution) level by reducing load (and hence the need for capacity transfers) by demand response (DR) programs. Consequently, DR programs in the distribution system may be put in place by transmission system operators via individual utilities' program offerings to end-users. This sequence of events has been driven by the efforts of the FERC to lower the cost of ancillary services, which have long been the sole domain of large generation providers.

Smart grid technologies will address transmission congestion issues through demand response and more: controllable loads, energy storage, distributed renewables and distribution automation. Diagnostic tools within the transmission system and smart-grid-enabled distributed controls will help dynamically balance electricity supply and demand; that will help the system respond to imbalances and limit their propagation when they occur.

Candidate controls and tools include demand response driven by price signals, as well as commercial or residential energy management systems. Such methods could reduce the frequency of outages and power disturbances attributed to grid overload. They could also reduce planned rolling brownouts and blackouts like those implemented during the energy crisis in California in 2000–2001. Smart grid technologies might quickly diagnose outages caused by physical damage of the transmission and distribution facilities due to weather, and even direct crews to repair them.[294]

A functional objective of the smart grid is to enhance reliability of the transmission and distribution systems. Smart grid reliability is described by DOE[295] as follows: "A Smart Grid that anticipates, detects and responds to problems rapidly reduces wide-area blackouts to near zero (and will have a similarly diminishing effect on the lost productivity)." A recent DOE report[296] on smart grid benefits addressed this issue by noting that a smart grid can improve reliability by preventing or limiting blackouts using wide-area control on the transmission level, and rapidly isolating and reconfiguring distribution system faults. Both of these activities can shorten outage durations from hours to minutes.

### A.10.2 Description of Metric and Measurable Elements

Several widely accepted metrics for measuring T&D reliability already exist in the industry. The System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI) describe the duration and frequency of sustained interruptions experienced by customers of an electricity service provider in one year. These metrics are the focus of this paper.

[294] Baer WS, B Fulton, and S Mahnovski. 2004. *Estimating the Benefits of the GridWise Initiative: Phase I Report.* TR-160-PNNL, prepared by Rand Science and Technology for Pacific Northwest National Laboratory, Richland, Washington.
[295] Litos Strategic Communication. 2008. *The Smart Grid: An Introduction*. Prepared by Litos Strategic Communication for the U.S. Department of Energy, Washington, D.C., p. 37. Accessed October 22, 2010 at http://www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages%281%29.pdf (undated webpage).
[296] Pratt RG, PJ Balducci, C Gerkensmeyer, S Katipamula, MCW Kintner-Meyer, TF Sanquist, KP Schneider, and TJ Secrest. 2010. *The Smart Grid: An Estimation of the Energy and $CO_2$ Benefits*. PNNL-19112, Rev. 1, Pacific Northwest National Laboratory, Richland, Washington. Accessed July 21, 2010 at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf (undated webpage).

(*Metric 10.a*) SAIDI represents the average number of minutes customers' power is interrupted each year, and is calculated as

$$SAIDI = \frac{\text{Sum of customer (sustained) interruption durations for all customers}}{\text{Total number of customers served}}$$

(*Metric 10.b*) SAIFI represents the total number of power interruptions per customer for a particular electric supply system, and is calculated as

$$SAIFI = \frac{\text{Total number of customer (sustained) interruptions for all customers}}{\text{Total number of customers served}}$$

(*Metric 10.c*) CAIDI represents the average outage duration that a customer experiences; alternatively stated, it is the average restoration time.

$$CAIDI = \frac{\text{Sum of durations of all customer interruptions}}{\text{Total number of customer interruptions}} = \frac{SAIDI}{SAIFI}$$

(*Metric 10.d*) MAIFI represents the total number of customer interruptions per customer lasting less than five minutes for a particular electric supply system, and is calculated as

$$MAIFI = \frac{\text{Total number of momentary (< 5 min) interruptions for all customers}}{\text{Total number of customers served}}$$

### A.10.3 Deployment Trends

The benchmarking study by the IEEE in 2011 analyzed SAIDI, SAIFI and CAIDI data from 90 companies in the U.S. and Canada, representing 69.8 million customers. Figure A.27 shows SAIDI, SAIFI, and CAIDI estimated within the studies published in 2003 through 2011. The primary axis (on the left) presents the minutes of interruption measured for the average customer served by the electricity service providers included in the survey and applies to the SAIDI IEEE and CAIDI IEEE results. The secondary vertical axis (at right) measures the number of interruptions per year and applies to the SAIFI IEEE metric. As shown, the trend has been flat over the past eight years. The year 2011 was no exception. From 2003 to 2011, there was no change in CAIDI and a slight increase in SAIDI.[297]

It is important to note that the 2011 IEEE benchmarking survey presented results for all interruptions and for interruptions as defined by IEEE Std 1366. The IEEE Std 1366 definition removes major events, largely tied to extreme weather, that require a crisis mode to respond adequately. The IEEE Std 1366 measure is viewed as a more reliable and accurate measure of system performance.

[297] IEEE – Institute of Electrical and Electronics Engineers. 2012. *IEEE Benchmarking 2011 Results*. Presented at the Distribution Reliability Working Group Meeting. San Diego, CA.

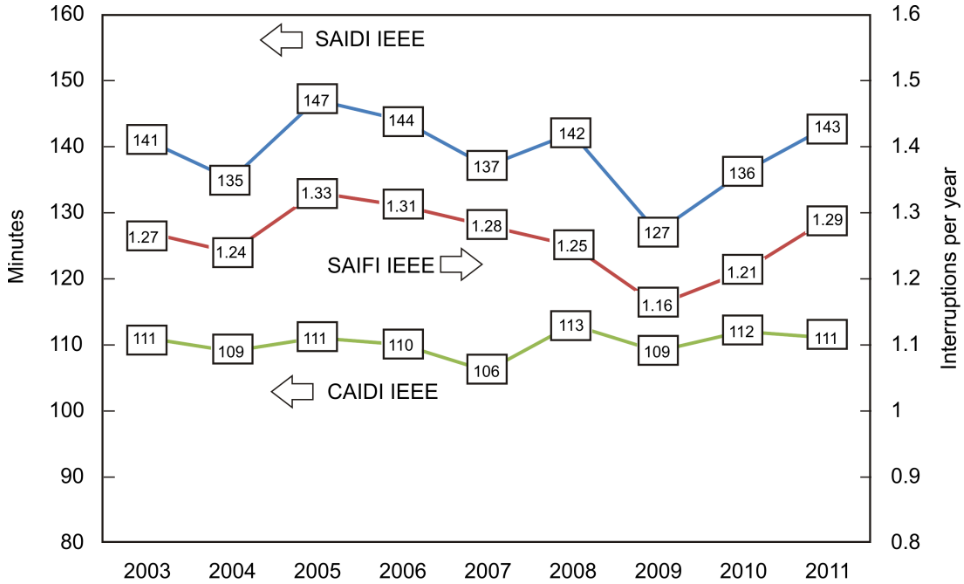



**Figure A.27**. SAIDI, SAIFI, and CAIDI Reported in 2003-2011 IEEE Benchmarking Reliability Studies

The 2010 benchmarking survey was completed by companies serving 78.6 million customers in the U.S. and Canada. The results of the IEEE 2010 benchmarking study are segmented by respondent size in Table A.13. SAIDI, SAIFI, and CAIDI All includes all incidents including major events that are not included in the IEEE Std 1366 measures.

As shown, SAIDI All and CAIDI All rose with the size of the respondent. SAIDI All was higher among small respondents (162.53) relative to large ones (247.69). CAIDI All also is higher among large respondents (167.84) compared to small respondents (108.79). SAIFI All is highest among medium respondents at 1.48 and lowest among large respondents, who registered at 1.35.[298]

[298] IEEE – Institute of Electrical and Electronics Engineers. 2011. *IEEE Benchmarking 2010 Results*. Institute of Electrical and Electronics Engineers, Inc., Piscataway, New Jersey. Accessed July 25, 2012 at http://grouper.ieee.org/groups/td/dist/sd/doc/2011-07-Benchmarking-Results-2010.pdf (undated webpage).

**Table A.13**. SAIDI, SAIFI, and CAIDI by Respondent Size

| | Small Respondents 2010 | | | | | | |
|---|---|---|---|---|---|---|---|
| Quartile | Measure | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 0 | Min | 48.91 | 48.91 | 0.65 | 0.72 | 61.39 | 68.33 |
| 1 | Q1[a] | 75.72 | 116.89 | 0.92 | 1.26 | 77.38 | 88.83 |
| 2 | Median | 120.99 | 162.53 | 1.24 | 1.43 | 97.13 | 108.79 |
| 3 | Q3 | 161.97 | 314.64 | 1.47 | 1.98 | 116.57 | 151.51 |
| 4 | Max | 548.39 | 1806.34 | 4.14 | 4.73 | 217.38 | 743.70 |
| | **Medium Respondents 2010** | | | | | | |
| Quartile | Measure | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 0 | Min | 21.43 | 42.29 | 0.42 | 0.68 | 20.61 | 29.02 |
| 1 | Q1 | 94.85 | 129.52 | 1.01 | 1.15 | 90.68 | 108.83 |
| 2 | Median | 131.84 | 210.27 | 1.23 | 1.48 | 106.26 | 133.90 |
| 3 | Q3 | 159.62 | 348.15 | 1.45 | 1.83 | 122.17 | 198.83 |
| 4 | Max | 418.40 | 1564.35 | 4.65 | 5.11 | 199.01 | 574.41 |
| | **Large Respondents 2010** | | | | | | |
| Quartile | Measure | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 0 | Min | 53.64 | 78.23 | 0.54 | 0.88 | 65.84 | 73.51 |
| 1 | Q1 | 94.27 | 142.48 | 0.90 | 1.09 | 89.85 | 121.52 |
| 2 | Median | 124.13 | 247.69 | 1.06 | 1.35 | 110.35 | 167.84 |
| 3 | Q3 | 157.73 | 326.67 | 1.24 | 1.62 | 128.39 | 237.42 |
| 4 | Max | 219.29 | 559.52 | 2.03 | 2.51 | 219.92 | 416.09 |

(a) Q1 = First Quartile; Q3 = Third Quartile

Of the 99 SGIG projects, 48 seek to improve electric distribution reliability. Most of these projects (42 of 48) are implementing automated feeder switching. Most of the distribution reliability projects are in the early stages of implementation and have not finished deploying, testing, and integrating field devices and systems. However, four projects reported initial results to DOE based on operational experiences through March 31, 2012. Initial results from these projects indicate that automated feeder switching reduced the frequency of outages, the number of customers affected by both sustained outages and momentary interruptions, and the total amount of time that customers were without power (as measured by customer minutes interrupted. Reductions in SAIFI have been reported in the 11 to 49 percent range.[299]

The smart grid interviews conducted for this report asked electricity service providers to present SAIDI, SAIFI, and MAIFI data for the most recent year for which data were available and compare actual data against the levels predicted prior to the year in question; findings from the interviews are summarized in Table A.14 (see Appendix B). Responses from each electricity service provider were weighted based on their share of the total customer base of those utilities providing data.

[299] DOE – U.S. Department of Energy. 2012. *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results.* Washington D.C. Accessed May 30, 2013 at http://www.smartgrid.gov/sites/default/files/doc/files/Distribution%20Reliability%20Report%20-%20Final.pdf.

**Table A.14**. Predicted and Actual SAIFI, SAIDI, and MAIFI

| Metric Name | Predicted | Actual |
|---|---|---|
| SAIFI | 1.2 | 1.1 |
| SAIDI | 126.4 | 120.2 |
| MAIFI | NA | 2.8 |

Planning-reserve margins, which affect reliability measures, demonstrate the forecast difference between capacity and peak electricity demand. The on-peak summer reserve margins projected by the NERC in its Long-Term Reliability Assessment are presented for 2011 through 2021 in Figure A.28. Prospective systems are those planned or under construction. The rise in the near term reflects the current decrease in overall electricity demand. As the U.S. economy recovers and demand rises, reserve margins are forecast to decline. Although reserve margins presented in this aggregated graph are not forecast to fall below the 15 percent NERC reference level, regional projections vary significantly.[300]

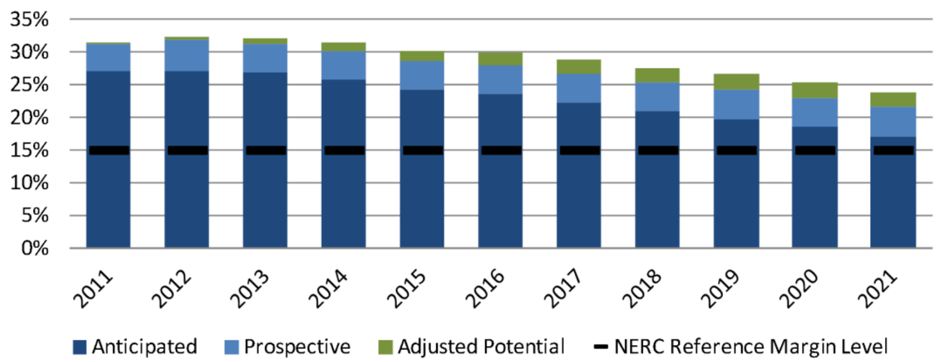



**Figure A.28**. U.S. On-Peak Summer Reserve Margins

NERC's *2011 Long Term Reliability Assessment* points to the economic recession as a factor influencing a decrease in projected future and conceptual generation resources, leading to a decline in planning reserve margins in some areas (Figure A.29). With that noted, the NERC assessment concludes that "most areas appear to have adequate resource plans to meet projected peak demands."[301]

[300] NERC – North American Electric Reliability Corporation. 2011. *2011 Long-Term Reliability Assessment.* North Princeton, New Jersey. Accessed July 25, 2012 at http://www.nerc.com/files/2011LTRA_Final.pdf (undated webpage).
[301] NERC 2011.

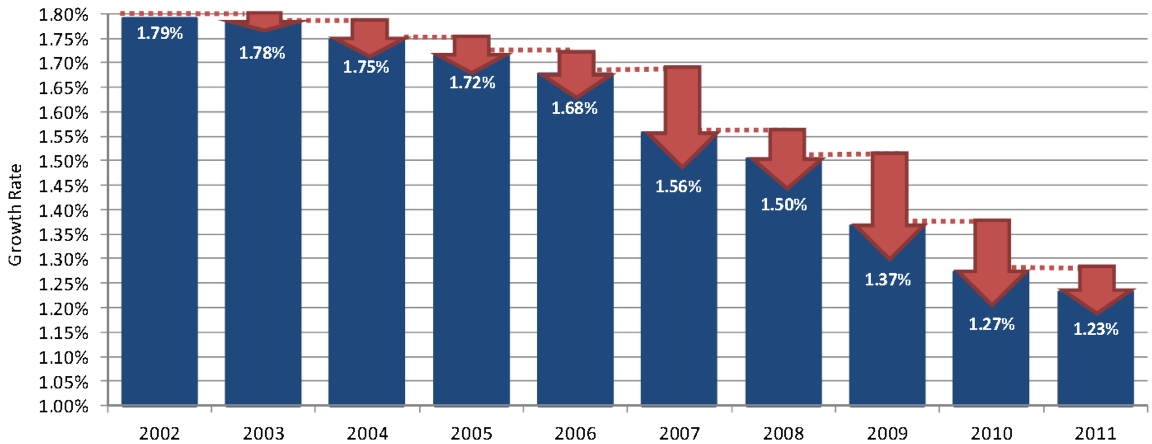



**Figure A.29**. Comparison of Annual Average Growth Rates for NERC-wide Summer Peak Demand

#### A.10.3.1 Associated Stakeholders

There are a number of stakeholders with interest in transmission and distribution reliability:

- electric-service retailers (wanting to cost-effectively provide a more reliable product)
- end-users (consumers seeking reliable power, at the 99.99 percent level—less than an hour per year of total outage time)
- local, state, and federal energy policy makers (concerned with the negative economic effects of poor power quality on commercial and industrial customers)
- regulators (who decide the basic level of power quality and reliability that the system will provide to customers).

#### A.10.3.2 Regional Influences

Reporting regulations and practices vary from state to state, making it difficult to compare these metrics across regions. Regional differences arise for several reasons, including climate, geography, and design and maintenance of the distribution system. Some utilities will naturally have better reliability indices than others because of differences in geography and natural vegetation and in frequency and types of severe weather in the region. For example, the number of lightning strikes, the length of exposed feeders, and urban network-system designs have significant impacts on reliability figures, regardless of the utilities' ability to operate and maintain their systems.[302] Each region of the country has a different combination (weighting) of customers (residential, commercial, and industrial) and each electricity service provider has its own unique distribution system, all of which affect T&D reliability.

The 2006 *National Electric Transmission Congestion Study* conducted by DOE investigated the Eastern and Western Interconnections to identify constrained transmission paths of national interest. Transmission congestion can indicate areas of system stress that can affect reliability as well as the cost of

[302] Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. ORNL/TM-2004/91. Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed July 25, 2012 at http://www.globalregulatorynetwork.org/Resources/measurementpractices0604.pdf (undated webpage).

electricity. Using scenarios projecting fuel prices for 2008 and 2011, the study identified 118 paths in the Eastern Interconnection that would be congested under almost every scenario. The western analysis modeled significantly larger nodes than the east and identified ten paths that were likely to be the most heavily congested in their 2008 projections, ordered by the number of hours during which usage is 90 percent or more of a line's limit. Overall, the study identified two critical congestion areas: 1) the Atlantic coastal area from New York to Northern Virginia, and 2) Southern California. Four congestion areas of concern were also identified (one in the east and three in the west). Five conditional congestion areas were also listed as situations to watch. It should be noted that DOE did not include the Electric Reliability Council of Texas in their study, because it was explicitly excluded in their directive from the *Energy Policy Act of 2005*.[303]

One of the biggest coming issues with regard to transmission reliability is integration of renewable resources such as wind and solar. The power from these resources needs to be moved from remote areas to population centers; the American Wind Energy Association sees this as an important issue.[304]

The 2009 *National Electric Transmission Congestion Study*[305] conducted by DOE observes that since the 2006 report, there has been much progress in the advancement of renewable energy resources. That suggests that the environment is more favorable. The DOE concluded in its 2009 congestion study report that there is only one nationally significant congestion area in the Eastern Interconnection, and that is the Mid-Atlantic area, reaching from south of Washington D.C. to north of New York City. For the Western Interconnection, the report found that all but one of the 2006 congestion areas continue to merit identification as congestion areas in 2009, indicating the Southern California Critical Congestion Area and the Seattle-Portland and San Francisco Congestion Areas of Concern. Note that the work is presently being updated, with a 2011 version posted for public comment. It is expected that a new version will be released in 2012.

## A.10.4 Challenges to Deployment

### A.10.4.1 Technical Challenges

Technical challenges include combining new technologies with existing technologies and updating the existing grid. The different characteristics of wind, solar, and nuclear power generation must be taken into account when planning. A NERC survey of industry professionals ranked aging infrastructure and limited new construction as the biggest challenges to reliability—both in likelihood of occurrence and potential severity. Lastly, more standardized codes, requirements, and reporting of T&D reliability are needed.[306]

---

[303] DOE – U.S. Department of Energy. 2006. *National Electric Transmission Congestion Study.* Washington, D.C. Accessed July 25, 2012 at http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/national (undated webpage).

[304] Goggin M. 2008. "Interstate Transmission Superhighways: Paving the Way to a Low-Carbon Future." *RenewableEnergyWorld.com*. Accessed July 22, 2010 at http://www.renewableenergyworld.com/rea/news/article/2008/07/interstate-transmission-superhighways-paving-the-way-to-a-low-carbon-future-53193 (last updated July 30, 2008).

[305] DOE – U.S. Department of Energy. 2009. *National Electric Transmission Congestion Study.* Washington, D.C. Accessed May 31, 2012 at http://energy.gov/sites/prod/files/Congestion_Study_2009.pdf (undated webpage).

[306] NERC – North American Electric Reliability Corporation. 2007. *Results of the 2007 Survey of Reliability Issues*, Rev 1. Washington, D.C. Accessed February 6, 2009 at http://www.nerc.com/files/Reliability_Issue_Survey_Final_Report_Rev.1.pdf (undated webpage).

### A.10.4.2 Business and Financial Challenges

Grid improvements involve costs that some may hesitate to incur. FERC, in a policy statement on matters related to bulk power system reliability, observed that public electricity service providers may be reluctant to spend significant amounts of money without reassurance that they will be able to recover it. The report goes on to note:

> *Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electricity system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices.*[307]

Electricity service providers have difficulty proving to regulators the exact cost/value relationship of particular measures. The difficulties arise because of the complex interactions between reliability programs and technologies. This lack of proof can make regulators hesitant to allow cost recovery.

Currently, there are irregularities in the ways utilities and regions report T&D reliability incidents. Definitions are sometimes vague, and inconsistencies in reporting requirements are making it difficult to complete analyses. For example, SAIDI, SAIFI, and MAIFI are useful for assessing T&D reliability, but often are not collected, or are collected inconsistently.[308] In a 2003 nationwide study by IEEE, several inconsistencies between electricity service provider practices were found. They found disparities in how start and end times of an interruption are reported and wide discrepancies in what defines a major event that would be excluded from reliability indices. Some utilities include MAIFI within SAIFI, which inflates SAIFI. Utilities differ on the level at which they measure reliability (e.g., substation, circuit breaker, meter), and interruption data are entered differently, either automatically by a computer or manually.[309] However, Eto *et al*. (2012) found that there was a general increase from 2000 to 2006 in the number of utilities reporting SAIFI and SAIDI, both with and without major events included.[310] The trend declined after 2006, and the authors suggest that this may be because data is still being processed by the utilities and their regulators, and was thus not available at the time the report was being prepared, rather than a decline in reporting (Figure A.30).

---

[307] FERC – Federal Energy Regulatory Commission. 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. Docket No. PL04-5-000, Washington, D.C. Accessed October 14, 2008 at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf (undated webpage).
[308] Kueck et al. 2004.
[309] Warren CA, DJ Pearson, and MT Sheehan. 2003. "A Nationwide Survey of Recorded Information Used for Calculating Distribution Reliability Indices." *IEEE Transactions on Power Delivery* 18(2):449-453, DOI:10.1109/TPWRD.2002.803693.
[310] Eto JH, K Hamachi LaCommare, P Larsen, A Todd and E Fisher. 2012. *An Examination of Temporal Trends in Electricity Reliability Based on Reports from U.S. Electric Utilities*. LBNL-5268E, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed June 2, 2012 at http://certs.lbl.gov/pdf/lbnl-5268e.pdf.


**Figure A.30**. Number of Utilities with SAIDI and SAIFI Data[32]

Another factor with the potential to affect reliability measurements is the way states regulate reliability, which can drive strategies for how to meet regulatory goals for reliability. Figure A.31, taken from a report prepared by Davies Consulting Inc. (DCI), shows the types of strategies that various states use to drive reliability requirements.[311] These strategies include quality-of-service targets, incentives, and penalties. The figure demonstrates how these strategies vary from state to state.[312]

The figure shows that some states are basing performance regulations (PBR) and monitoring on Return on Equity (ROE) and others on Quality of Service (QOS). The differences between states arise for several reasons. The service areas are different in such factors as population density and climate, both of which can affect power system design and operation, and therefore reliability. Further, the effort required by the state regulators to implement and monitor the requirements is not the same from state to state (as some may have more utilities reporting than others, for example). For these reasons, there is presently no uniformity across the country.

In a sense, this situation allows some evolution of reliability metrics. New metrics are emerging that concentrate less on system reliability (the "S" in SAIDI and SAIFI) and less on the average performance (the "A" in those metrics). The new interest is more on the individual experience. How many customers are experiencing multiple outages? What is the longest outage experienced? What is the impact of vegetation management programs?

[311] Davies Consulting Inc., "State of Distribution Reliability Regulation in the United States" prepared for Edison Electric Institute, September 2005, accessed August 2012 at http://legalectric.org/f/2010/04/stateofdistributionreliability-2005.pdf

[312] Eto JH, and K. Hamachi LaCommare, Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions available at http://www.smartgrid.gov/sites/default/files/doc/files/eto%20oct%202008.pdf accessed August 2012.

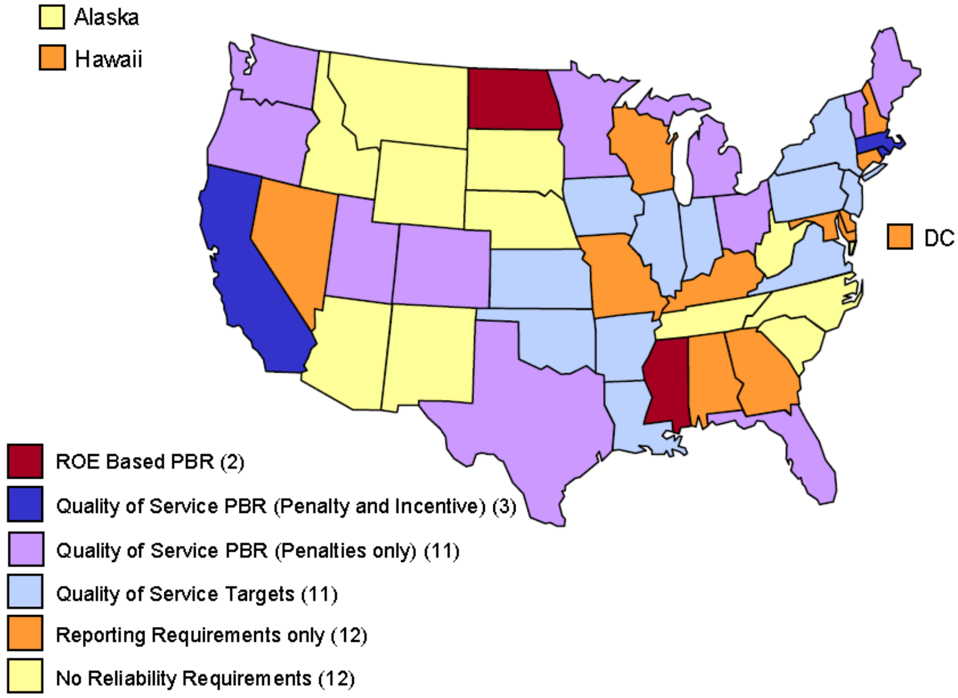



**Figure A.31**. Regulatory Requirements for Reliability

## A.10.5 Metric Recommendations

More interviews should be conducted in support of future smart grid benchmark studies and the Energy Information Administration should be engaged and encouraged to add SAIDI, SAIFI, MAIFI, and CAIDI to their electricity service provider surveys.

# A.11 Metric #11: Transmission and Distribution Automation

## A.11.1 Introduction and Background

Transmission and distribution (T&D) automation may be defined as a system that enables an electricity service provider to remotely monitor, coordinate, and operate the power delivery system. The metric used in this report includes the coordination of T&D components that are separate, but may be co-located. This somewhat broader meaning encompasses a large set of technologies, including SCADA, remote sensors and monitors, switches and controllers with embedded intelligence and digital relays.

The general operating scheme of such devices is to gather real-time information about the grid through communication, process the information on site, take immediate corrective action if necessary, and communicate results back to human operators or other systems. The devices serve a variety of functions that have long been discussed and planned, including not only the fault location and fault isolation of the protective relaying system, but also feeder reconfiguration, service restoration, remote equipment monitoring, feeder load balancing, volt-VAR controls, and a variety of remote system measurements.[313] T&D automation systems can provide more reliable operation, increased responsiveness and better system efficiency.

This improved operation comes at a cost. Public and private funding of smart grid applications has grown during the past few years, aided by energy efficiency initiatives, renewable portfolio standards and government stimulus actions. According to a report from Pike Research, global spending on smart grid technologies is estimated to top $200 billion between 2008 and 2015, with grid automation systems capturing 84 percent of the market and AMI capturing 14 percent.[314]

Financed by the *American Recovery and Reinvestment Act of 2009* (ARRA), DOE's Smart Grid Investment Grant (SGIG) program has funded a wide range of technology to add automation features to the U.S. grid. Automated feeder switches improve reliability (reduced outages), while automated regulators and capacitors with appropriate control technology provide near real time voltage and reactive power management, which improves energy efficiency and system flexibility.

The SGIG program is investing $3.4 billion over a period of 3 to 5 years. As of September 30, 2012, ARRA had funded the installation of 6,770 automated feeder switches (at a cost of $376.3 million), 10,408 automated capacitors ($94.7million), 6,905 automated regulators ($27.1 million), 3,913 feeder monitors ($107.1million) and 15,376 substation monitors ($111.7 million).[315] There are 671 substation

---

[313] An excellent overview of the topic is found in a 2007 report by EPRI to the California Energy Commission, *Value of Distribution Automation Applications*, CEC 500-2007-028. It can be found at http://www.energy.ca.gov/2007publications/CEC-500-2007-028/CEC-500-2007-028.PDF (accessed June 1 2012)

[314] Pike Research. 2009. "Smart Grid Investment to Total $200 Billion Worldwide by 2015." Boulder, Colorado. Accessed July 21, 2010 at http://www.pikeresearch.com/newsroom/smart-grid-investment-to-total-200-billion-worldwide-by-2015 (last updated December 28, 2009).

[315] DOE – U.S. Department of Energy. 2012. "Deployment Status." In *Recovery Act Smart Grid Program*, SmartGrid.gov, Washington, D.C. Accessed December 12, 2012, at http://www.smartgrid.gov/recovery_act/deployment_status/distribution (Last updated December 11, 2012).

automation projects in the SGIG investment program,[316] representing 5 percent of the total 12,466 T&D substations in the U.S. These figures represent total cost, which is the sum of the federal investment and cost share of the recipient. As of September 30, 2012, the Smart Grid Demonstration Program (SGDP) had co-funded the installation of an additional 497 automated feeder switches, 341 automated capacitors, and 13,021 feeder monitors.[317]

Of the 99 SGIG projects, 48 seek to improve electric distribution reliability. Most of these projects (42 of 48) are implementing automated feeder switching. Most of the distribution reliability projects are in the early stages of implementation and have not finished deploying, testing, and integrating field devices and systems. However, four projects reported initial results to DOE based on operational experiences through March 31, 2012. Initial results from these projects indicate that automated feeder switching reduced the frequency of outages, the number of customers affected by both sustained outages and momentary interruptions, and the total amount of time that customers were without power (as measured by customer minutes interrupted). Reductions in SAIFI have been reported in the 11 to 49 percent range.[318]

### A.11.2 Description of the Metric and Measurable Elements

The metric for automation technology adoption is defined as:

*(Metric 11) Percentage of substations having automation.*

### A.11.3 Deployment Trends and Projections

Data from utilities across the nation show a clear trend of increasing T&D automation and increasing investment in these systems. Drivers for the increase in investment include operational efficiency and reliability improvements to drive cost down and overall reliability up. The lower cost of automation with respect to T&D equipment (e.g., transformers, line switching) is also making the value proposition easier to justify.

To evaluate the level of T&D automation among electricity service providers, interviews conducted for this study included questions regarding the percentage of substations equipped with various levels and forms of automation. The weighted results of these interviews (see Appendix B) indicate that:

- 85.7 percent of the total substations owned by electric services providers interviewed for this study were automated. This number is a significant increase over that in the 2010 Smart Grid System Report (47.7 percent).
- 93 percent of the total substations owned had outage detection, up from 78.2 percent.
- 93.6 percent of total customers had circuits with outage detection, up from 82.1 percent.

[316] Ton D. 2009. *DOE's Perspectives on Smart Grid Technology, Challenges, & Research Opportunities*. Presented at the UCLA HSSEAS Smart Grid Seminar Series, November 19, 2009, Los Angeles, California. Accessed October 26, 2010 at http://www.ita.ucla.edu/news/presentations/Ton-UCLA1119-rv.pdf (undated webpage).

[317] Wang, W. 2013. Personal Communication. *Data Compiled from ARRA Recipient's Federal Financial Reports (FFR) SF-435*. May 31, 2013.

[318318] DOE – U.S. Department of Energy. 2012. *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results.* Washington D.C. Accessed May 30, 2013 at http://www.smartgrid.gov/sites/default/files/doc/files/Distribution%20Reliability%20Report%20-%20Final.pdf.

- 58.4 percent of total relays were electromechanical relays, up from 46.4 percent.
- 41.5 percent of total relays were microprocessor-based relays, up from 13.4 percent.

Other nationwide data has shown that transmission automation is already widely deployed, while distribution automation is employed on a more limited basis. Most of the distribution automation being implemented is in the substations, where communication distances are short and where most of the switching and control equipment is located. Feeder equipment automation is less prevalent. Recent research shows that while 84 percent of utilities had substation automation and integration plans underway in 2005, and about 70 percent of utilities had deployed SCADA systems to substations, only 10–12 percent of substations were reported as automated as of the end of 2010.[319] The penetration of feeder automation among utilities is growing, according to John McDonald, a past president of the IEEE Power and Energy Society and Director of Technical Strategy and Policy Development at General Electric (GE). Mr. McDonald estimates that the payback period for feeder automation is less than three years.[320]

It is worth noting that, aside from the interview data presented here, there is a lack of data regarding the penetration of T&D automation. The lack of information makes it difficult to directly draw conclusions about the impact of these devices on the actual performance of the grid. Investment information can be obtained, however.

T&D technology development and deployment is expected to grow in the future, while capital expenditures by utilities are expected to maintain present levels. Recent studies[321] indicate that 2010 electricity service provider investments in T&D infrastructure held steady despite the current economic climate. Interestingly, a recent study completed by Newton-Evans indicates that government programs are evidently less of a factor on capital expenditure (CAPEX) increases than in earlier years, though still important at 57 percent. The results of a 2011 Newton-Evans study on CAPEX investment are presented in Table A.15. As shown, electricity service provider CAPEX budgets were generally positive compared to earlier results. Organizations from 25 countries participated in the study, and a majority indicated that planned T&D budgets increased or were unchanged in 2011 and 2012.

---

[319] Newton-Evans Research Company. 2011. In "World Market for Substation Automation and Integration Programs in Electric Utilities: 2011-2013" Accessed August 1, 2012 at http://www.newton-evans.com/increases-in-substation-related-automation-and-integration-program-spending-reported-by-north-american-electric-power-utilities-2/ (webpage material dated January 4, 2011).
[320] Fiercesmartgrid.com. 2012. "Smart Grid Substation and Feeder Automation." Accessed August 1, 2012 at http://www.fiercesmartgrid.com/story/smart-grid-substation-and-feeder-automation/2012-02-07 (last updated February 7, 2012).
[321] Newton-Evans. 2011. *Market Trends Digest: March 2011*. Accessed July 21, 2012 at http://www.newton-evans.com/mtdigest/mtd1q11.pdf (undated webpage).

**Table A.15**. Comparison of 2011 and 2012 Planned CAPEX Investment for T&D[322]

| Smart Grid Component and Infrastructure Category | Increase | | No Change | | Decrease | |
|---|---|---|---|---|---|---|
| | 2011 | 2012 | 2011 | 2012 | 2011 | 2012 |
| Energy Management Systems (EMS)<br>Supervisory Control and Data Acquisition (SCADA)<br>Distribution Management Systems (DMS) | 50% | 49% | 45% | 45% | 5% | 6% |
| Substation Automation & Integration | 51% | 47% | 41% | 49% | 8% | 5% |
| Protection & Control | 43% | 49% | 52% | 49% | 5% | 2% |
| Distribution Automation | 45% | 52% | 51% | 45% | 4% | 3% |
| Advanced Metering Infrastructure (AMI) | 48% | 43% | 45% | 48% | 7% | 9% |
| Transmission Infrastructure | 49% | 57% | 39% | 32% | 12% | 11% |

CAPEX expenditure data is also included in a Price Coopers Waterhouse report[323] (Figure A.32), which outlines spending from 2004 to 2009 and includes estimates of investment between 2010 and 2012.

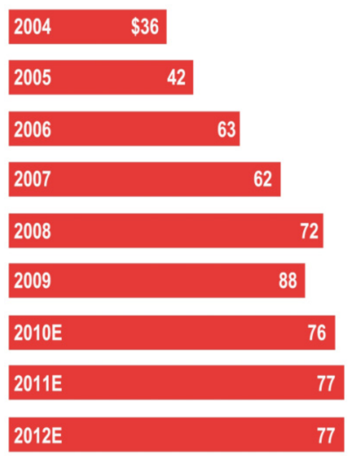



**Figure A.32**. U.S. Electricity Service Provider Capital Expenditures (2004 to 2012 estimate—$billions)

### A.11.3.1 Stakeholder Influences

The major stakeholders in T&D automation, or those that are directly affected by the performance of this infrastructure, include

- transmission providers (as owners and operators of the assets to be maintained and upgraded)
- distribution-service providers (as owners and operators of the assets to be maintained and upgraded)
- energy policy makers:
  - local (as regulatory entities for publicly owned companies)
  - state (as regulatory entities for investor-owned T&D companies)
  - federal (as enforcement entities for reliability)

[322] Newton-Evans 2011.
[323] Sulavik C. 2010. *Smart Grid Growing Pains*. PricewaterhouseCoopers, LLP. Accessed July 21, 2010 at http://www.metering.com/wp-content/uploads/i/Smart_Grid_Growing_Pains.pdf (undated webpage).

- financial community – will need to provide capital for the required upgrades
- reliability coordinators – ensuring that electricity quality and reliability are maintained
- vendors – provide technology and enhancements
- end-users – consumers, who stand to gain from higher and more-cost-effective reliability.

#### A.11.3.2 Regional Influences

There is no single best method for adding an automation scheme to improve system performance because power systems are not built or operated according to a single plan. The integrated and interconnected power system of today began as separate distribution systems, supplying customers from local generation sources. Some were direct current (DC), some alternating current (AC). For AC, even the frequency was not fixed until the 1930s. As it happens, Los Angeles was one of the last to change to 60 hertz (Hz), a decision made in response to the availability of power from Hoover Dam. Until this point, LA had operated part of its system at 50 Hz and part at 60 Hz; Hoover Dam power was 60 Hz.

In general, while the interconnecting transmission systems have many similarities, there are still many differences between the distribution systems around the country. These differences mean that different automation schemes are appropriate. For example:

- The highly dense urban core of New York City is a mesh distribution network (truly a grid). As a way to supply reliable power, such a scheme lends itself to distribution automation systems that include increased monitoring.
- Rural areas, which comprise most of the square miles of the U.S., use long radial feeders. A failure on one of these might require hours of driving for electricity linemen just to locate the problem. Such situations are good candidates for remote monitoring and control, but note that the communications requirements for this sort of control are very different than those for the New York grid.
- Cities such as San Diego use a well-connected network system and a radially operated distribution scheme. This sort of arrangement lends itself to a variety of automatic fault-detection and feeder-reconfiguration schemes.

In addition, there are significant differences in the vintages of the distribution system, and significant differences in the operating practices. Some companies limit the load on any given feeder to 50 percent of its rating, so that in the event of a fault, some (or all) of the load can be picked up by back-feeding from another feeder. Others allow lines to be much more fully loaded.

The overhead distribution system that is used in most suburban and rural situations operates at a voltage of around 10 to 20 kilovolts (kV), the exact value depending on some historical decision. Many utilities are involved in converting this infrastructure to underground cables (much more costly, but more reliable), and also to higher voltages. A line feeding a load at 12 kV would have about a quarter of the losses if it were rebuilt for 24 kV, for example, because the losses in a line go as the square of the current, and the current would be halved if the voltage were doubled.

Southwestern and southeastern regions have seen significant load growth in the last decades, which led to new T&D expansions with more modern technology. In contrast, established East Coast and Midwest cities tend to retain dated systems that are a half-century old or more.

## A.11.4 Challenges

### A.11.4.1 Technical Challenges

Replacement of aging equipment, and regulators' focus on benchmarks such as the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), along with the need to reduce costs via automation, are beginning to bear fruit in the form of real cases of self-healing distributions systems. The need for electricity service providers to prepare for implementation of the smart grid functions for self-healing capabilities or remote operation will continue. This means that the system must be capable of operating in new ways—for example, with two-way power flow resulting from the installation of distributed energy resources. Furthermore, the state of distribution system modeling software does not allow analysis of the dynamics of distributed generation. The amount of engineering effort needed to accomplish the necessary changes exceeds what is normal for the distribution system, and becomes a cost issue.

Even with the increased focus on automation, preparation to reach important milestones has not been adequately completed according to a survey[324] performed by Energy Central's research arm, Sierra Energy Group. Of more than 90 investor-owned utilities (IOUs) surveyed, their answers demonstrate a marginal level of preparedness, as shown below in Figure A.33.

How close is your electricity service provider to having the grid be self-healing?

| NOT PREPARED 1 | 2 | 3 | 4 | FULLY PREPARED 5 | RATING Average |
|---|---|---|---|---|---|
| 19.8% | 45.1% | 27.5% | 7.7% | 0.0% | 2.23 |

How close is your electricity service provider to being able to operate the distribution grid remotely?

| NOT PREPARED 1 | 2 | 3 | 4 | FULLY PREPARED 5 | RATING Average |
|---|---|---|---|---|---|
| 7.7% (7) | 27.5% (25) | 42.9% (39) | 19.8% (18) | 2.2% (2) | 2.81 |

**Figure A.33**. IOU Automation Preparedness Survey Responses (on a five point scale)[325]

### A.11.4.2 Business and Financial Challenges

Challenges in T&D automation for transmission differ from those for distribution. Methods for transmission-side automation are fairly well known, but deployment is limited by funding and institutional barriers.[326] Distribution-side automation has seen an influx of new technologies, taking advantage of recent advances in measurements, communications and low-cost computing. However, there are few convincing options for modeling the cost and performance effects of these new technologies

[324] Causey W. 2008. "The Pursuit of Automation." *Guidebook: Transmission & Distribution Automation*,. EnergyBiz, p. 58. Accessed 21 July 2010 at http://energycentral.fileburst.com/Sourcebooks/gsbk0108.pdf (undated webpage).
[325] Causey 2008.
[326] EnergyBiz Magazine. 2006. *Guide & Sourcebook: Transmission & Distribution Automation*. Pp 51-66. Accessed October 28, 2008 at http://energycentral.fileburst.com/Sourcebooks/gsbk0106.pdf (undated webpage).

on utilities. Thus, the business case for these schemes is difficult to make. For example, means may be installed to ensure that the voltage of the power delivered is close to its nominal value, even at the remote end of a distribution line. While claims are made that such a scheme is cost-effective, the case is actually hard to make. Increasingly, the load on a power line is not greatly affected by the voltage. On the one hand, loads such as pump or air-conditioner motors may fail (or trip off because of overheating) if the voltage is outside the normal limits. On the other hand, most lap-top computers will accept anything from 100 to 240 volts, for example, and some light-emitting diode lights will do the same.

Many utilities who traditionally have not had systems for managing their distribution networks outside the level of the substation are finding that the transition to automated T&D systems is expensive. The costs are due to two factors: the large scale of the communication and control systems needed, and the increased level of engineer effort required.

Sensing and monitoring systems are not costly in the absolute sense, but the case must be made to public utility commissions who see a system that seems to work without them. Proving the value of these automation technologies through demonstration projects is thus an important first step toward gaining regulatory acceptance. As with transmission automation, however, institutional barriers must be removed before high-level acceptance of this technology can foster widespread deployment.

The engineering required to implement a distribution-automation scheme offers some new challenges from a technical point of view. The solutions to the various problems require careful consideration, almost always on a case-by-case basis, and almost always involve the use of information that has not historically been available.

In the past, it has not been possible to devote a large engineering effort to the distribution system because (for example) the number of customers on a distribution line is tiny compared to the number of customers served by a transmission line. The cost impact has led to a culture in which distribution systems have been built according to pre-calculated "recipes" rather than engineered from scratch. Solving the new engineering problems of distributed energy sources, demand response and storage requires a revision to the culture and the costs.

Business-case tools are standards tools for vendors selling technology, and service providers are beginning to understand better the need for "selling" technology advancement within their own organizations and to regulators. Technology road mapping is becoming a common tool to reach internal and external audiences. Providers or vendors that are using technology road mapping successfully to organize research and development efforts or implement smart grid strategies include the Bonneville Power Administration[327], Southern California Edison[328] and GE.[329] A sample diagram detailing the road mapping process[330] is shown below in Figure A.34

[327] BPA – Bonneville Power Administration. Undated. "Transmission Technology Roadmaps." *Technology Innovation.* Portland, OR.

[328] SCE – Southern California Edison. 2010. *Southern California Edison Smart Grid Strategy & Roadmap*. Accessed July 22, 2010 at http://www.sce.com/NR/rdonlyres/BFA28A07-8643-4670-BD4B-215451A80C05/0/SCE_SmartGrid_Strategy_and_Roadmap.pdf (undated webpage).

[329] Berst J. 2009. "Behind-the-Scenes Look at GE's Smart Grid Strategy." *Smart Grid® News.com*. Accessed July 22, 2010 at http://www.smartgridnews.com/artman/publish/companies/Behind-the-Scenes_Look_at_GE_s_Smart_Grid_Strategy-663.html (last updated August 4, 2009).

[330] Farquharson R. 2009. "Smart Grid 101: Utility Applications and Roadmaps." Presented at the *2009 IEEE PES General Meeting*, July 27, 2009, Calgary, Alberta.

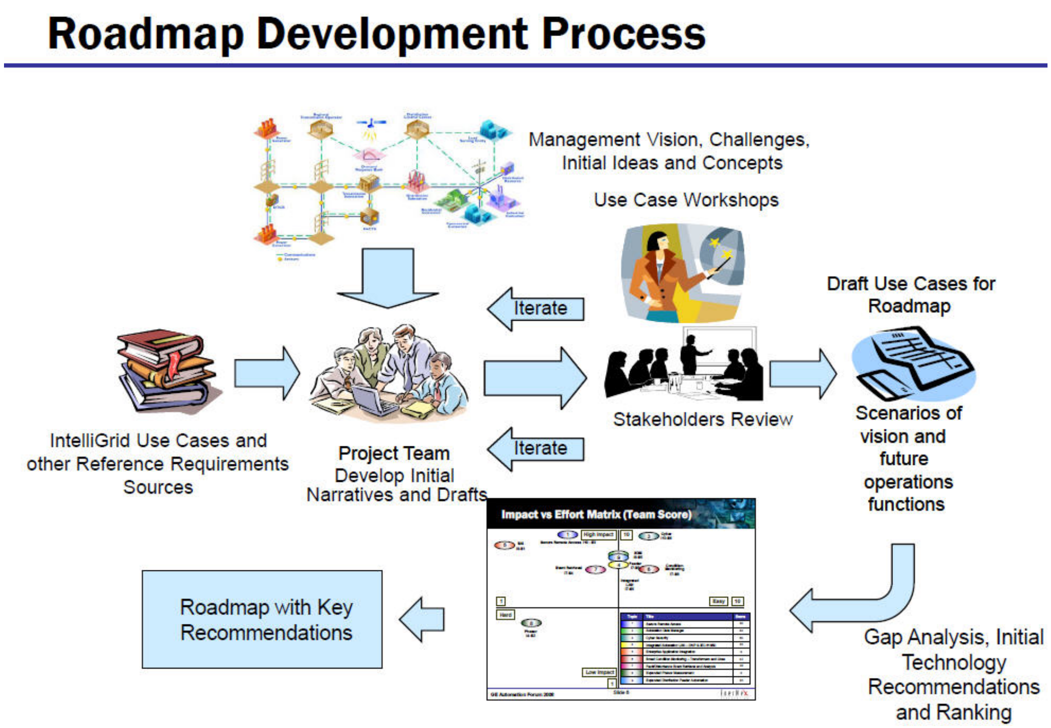



**Figure A.34**. Sample Technology Roadmap Development Process[331]

## A.11.5 Metric Recommendations

This metric should as far as possible consist of directly measurable or numeric values. Qualitative metrics describing how automation components are used are less meaningful. A few metrics can be chosen from the many described below.

The quantitative metrics consist of an estimation of the rate of deployment of technology and automation, and the amount of investment for automation products to capture the economic activity.

- *(11.a) Percentage of substations having automation (the metric used for this report)*
- *(11.b) Percentage of substations with outage detection*
- *(11.c) Percentage of circuits with fault-detection and -localization capabilities*
- *(11.d) Number of automated substations*
- *(11.e) Number of electromechanical relays*
- *(11.f) Number of microprocessor relays*
- *(11.g) Number of intelligent electronic devices (IEDs) deployed*
- *(11.h) Percentage of distribution circuits with automated (or remotely automated) sectionalization and reconfiguration capabilities*

---

[331] Von Dollen D. 2007. *IntelliGrid Technology Transfer and Information Systems*. Electric Power Research Institute, Palo Alto, California. Accessed January 17, 2011 at http://intelligrid.epri.com/IntelliGrid_Project_Set_Calls/2009/P161A_Webcast_8.21.09/ps161a_webcast.pdf (undated webpage).

- *(11.i) Percentage of distribution circuits with feeder load-balancing strategies*

The investment metrics are defined as annual expenditures in dollars for:

- *(11.j) Protective relays*
- *(11.k) Feeder/switch automation*
- *(11.l) Control-center upgrades*
- *(11.m) Substation measurement and automation*
- *(11.n) Distribution automation.*

Based on the scale for degree of automation proposed by Sheridan,[332] the following qualitative metrics are suggested:

- *(11.o) Operational T&D control action performed manually by linemen or operators in central control centers.*
- *(11.p) Distributed electronic and computing devices detect normal and fault conditions and offer a set of action options.*
- *(11.q) IEDs narrow the options down to a few, or suggest one. For instance, system fault localization and suggestions for fault isolation and feeder reconfiguration.*
- *(11.r) IED recognizes a fault and executes a suggestion after operator/human approval. For instance, IEDs support an overarching control strategy that performs immediate remedial actions such as feeder reconfiguration and autonomous system restorations.*
- *(11.s) IED recognizes fault, then executes remedial actions automatically and informs the operator after execution.*

[332] Sheridan TB. 1992. *Telerobotics, Automation, and Human Supervisory Control*. MIT Press, Cambridge, Massachusetts.

# A.12 Metric #12: Advanced Meters

## A.12.1 Introduction and Background

A major element of smart grid implementation projects continues to be advanced meters and their supporting infrastructure, or advanced metering infrastructure (AMI), with ever-increasing numbers of electric service providers moving toward full AMI deployment. In 2009, the American Recovery and Reinvestment Act (ARRA) allocated $4.5 billion in grants to invest in smart grid technologies, including AMI infrastructure.

The Edison Foundation recently estimated that approximately 65 million smart meters will be deployed nationwide by 2015, which represents approximately 45 percent of customers in the country (IEE 2012). ARRA funding will result in approximately 15.5 million new smart meters, or approximately 24 percent of those that will be deployed by 2015

For this report, the FERC and EIA definition of AMI is used:

> "Advanced meters: meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data."[333]

In 2010, FERC collaborated with the EIA in an effort to monitor AMI deployment in a consistent manner. As such, the revised definition of AMI presented above could have resulted in changes in AMI counts by some respondents of the 2010 FERC Survey.[334] This change impacts regional deployment numbers, particularly in Florida (see Section A.12.3.2, Regional Influences).

Smart grid system implementation relies on a variety of AMI technologies that provide two-way communication between the customer and the electric service retailer. Figure A.35 illustrates the flow of metering data between the consumer home area network (HAN), AMI technologies such as smart meters or gateways, and information technology (IT) systems. HAN communications access AMI data and can also serve as the gateway from the service provider to the meter. This communication system can operate though wired, wireless, open or proprietary networks, and supply/communicate a variety of consumer and electricity service provider applications such as energy awareness, demand response, and distributed generation.

AMI technologies enable the communication of real-time pricing data, grid conditions, and consumption information. When smart meters are coupled with other enabling technology, such as programmable communicating thermostats and data management systems, information can be gathered and monitored by both the service provider and the consumer. Such data can enable demand response, dynamic pricing, and load management programs.

---

[333] FERC – Federal Energy Regulatory Commission. 2011a. *Assessment of Demand Response & Advanced Metering*. Staff Report, Washington, D.C. Accessed February 14, 2012 at http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf.

[334] FERC 2011a.

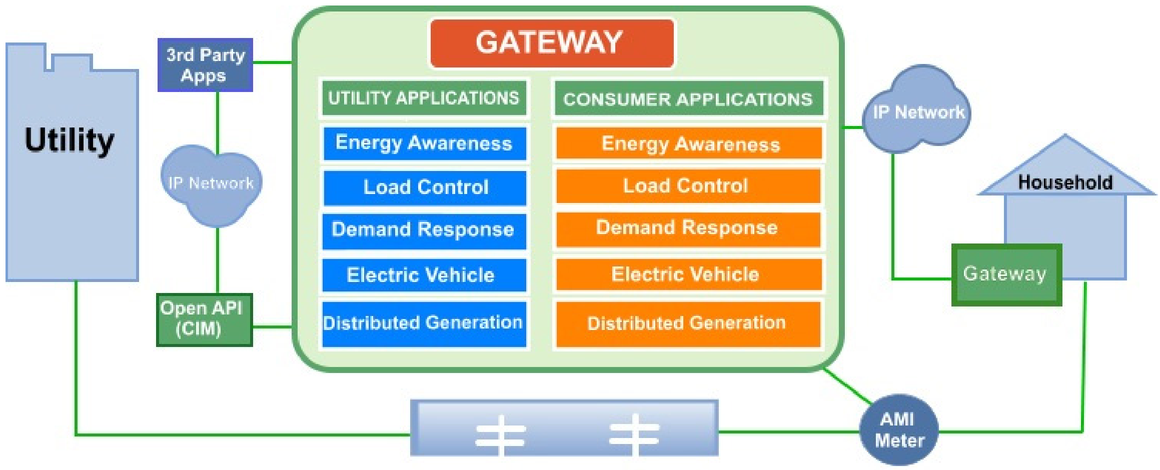



**Figure A.35**. Overview of AMI Interface[335,336]

Capabilities of AMI that benefit both consumers and electric retailers include dynamic pricing and demand response. As the ratio of peak electricity demand and average demand increases, dynamic pricing has the potential to help meet load requirements of the grid.[337] Closely related to dynamic pricing, "demand response" refers to changes in energy consumption by end-users in response to electricity costs that vary over time, in response to incentives from energy providers, or when system reliability is jeopardized.[338] Implementation of AMI technologies allows full realization of advanced smart grid systems through the following:

- automatically adjusting energy prices in peak hours or situations (dynamic pricing)
- allowing customers to manually respond to dynamic pricing by adjusting thermostats or changing peak-consumption patterns
- allowing customers to automatically respond to dynamic pricing through automated technology, such as a programmable communicating thermostat and smart appliances
- direct load control by utilities
- interruptible tariffs
- backup generation for distributed generation
- permanent load shifting
- supporting EVs and PHEVs.[339]

[335] Adapted from the Tendril Platform at http://www.tendrilinc.com/platform.
[336] IP – Internet Protocol, Apps – Applications, API -- Application Programming Interface, CIM -- Common Information Model
[337] MIT – Massachusetts Institute of Technology. 2011. *The Future of the Electric Grid: An Interdisciplinary MIT Study*. Cambridge, Massachusetts. Accessed March 17, 2012 at http://web.mit.edu/mitei/research/studies/documents/electric-grid-2011/Electric_Grid_Full_Report.pdf.
[338] FERC 2011a.
[339] FERC 2011a.

## A.12.2 Description of the Metric and Measurable Elements

The following two measurements have been identified as important for understanding and quantifying advanced metering. Meters will have to meet the minimum qualifications set by FERC to be counted in these measurements.

*(Metric 12.a) Number of meters planned or installed.* Tracking this number across states and regions will allow the United States to establish a baseline and a growth model for advanced meter penetration.

*(Metric 12.b) Percentage of total demand served by AMI customers.* Knowing the percentage of the grid's load served by AMI technology will enable system operators to better manage load and deploy demand-response measures.

## A.12.3 Deployment Trends and Projections

ARRA projects are deploying and testing a variety of communications and control schemes, including distributed and centralized control systems with various levels of integration among information management systems (e.g., outage management systems, distribution management systems, AMI, and geographic information systems). Multiple options are available depending upon location-specific conditions and utility objectives.

The number of advanced meters meeting the requirements of Metric 12.a grew from approximately 6.7 million meters in 2007[340] to approximately 36 million in 2012.[341] Coupled with approximately 148 million electric customers in the U.S. (commercial, industrial and residential), penetration equates to approximately 24.4 percent of total customers (Metric 12.b), up from 4.4 percent reported in the 2010 SGSR.

In 2011, EIA began collecting data on green pricing, net metering and AMI through Forms EIA-861, *Annual Electric Power Industry Report,* and EIA-826, *Monthly Electric Utility Sales and Revenue Data*. According to latest EIA data, almost 16.8 million smart meters were installed in 2011, serving a total of over 33.3 million megawatt-hours.[342] The 2010 FERC survey included 12.8 million meters installed nationwide as of December 2009, representing 8.7 percent of all meters in the U.S.[343] Independent analyses of AMI penetration conducted by the Institute for Electric Efficiency (IEE) indicate deployments nationwide expanded to an estimated 26.7 million in 2011, representing 18 percent of U.S. electric meters, and 36 million by May 2012. [344] Estimates from IEE are greater than those from FERC due to the inclusion of installed meters that have not yet been activated for AMI purposes. Additionally, the Cleantech Group estimated that 12 million meters were installed at the end of 2009, increasing to 20

[340] FERC – Federal Energy Regulatory Commission. November 2011b. *Assessment of Demand Response & Advanced Metering.* Staff Report, Washington, D.C. Accessed June 4, 2012 at http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf.

[341] IEE-Institute for Electric Efficiency. 2012. *Meter Deployments, Plans & Proposals.* Washington, D.C. Accessed October 17, 2013 at http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterRollouts_0512.pdf.

[342] EIA – U.S. Energy Information Administration. 2011a. *Electricity Data. Net Metering and Green Pricing. Advanced Metering - Number of Meters by Type and Megawatthours Served, by State by Sector*. Accessed May 30, 2012 at http://205.254.135.7/electricity/data.cfm#sales.

[343] FERC 2011a.

[344] IEE 2012.

million in 2010.[345] Cleantech Group's analysis is primarily based on shipment data. Table A.16 presents estimates of AMI penetrations by all organizations.

Load served by AMI can only be approximated at this time. FERC's demand assessment report indicates several categories of demand response deemed to require some form of AMI to be used, including critical peak pricing, critical peak pricing with load control, demand bidding and buyback, peak-time rebate, real-time pricing, time-of-use pricing, and direct load control. Direct load control could have either AMI or some other controller and thus may or may not include AMI[346]. Therefore, load using AMI was estimated both with direct load control and without it to give a range. Demand response accounted for 58 MW in 2010 with AMI accounting for 16 percent to 33 percent of the total, an increase from 41 MW of demand response in 2008. The low end of the range increased from 14 percent while the upper end decreased from 44 percent. The decrease was due to a large decrease in direct load control.[347]

**Table A.16**. Estimates of Advanced Meter Penetration Rates[348,349,350,351]

| Source of Number of Advanced Meters | Reference Date (mo./yr.) | Advanced Meter Penetration Rates (advanced meters as % of total meters) | Number of Advanced Meters (millions) |
|---|---|---|---|
| 2008 FERC Survey | Dec-07 | 4.7% | 6.7 |
| 2010 FERC Survey | Dec-09 | 8.7% | 12.8 |
| EIA-861 Annual Survey | Dec-09 | 6.5% | 9.6 |
| Cleantech Group | Dec-09 | 8.1% | 12 |
| Cleantech Group | Dec-10 | 13.5% | 20 |
| Institute for Electric Efficiency | Sep-11 | 18.4% | 27 |
| EIA-826 Monthly Survey | Dec-11 | 11.3% | 16.8 |
| Institute for Electric Efficiency | May-12 | 24.2% | 36 |

The IEE projects that AMI deployment will reach over 65 million meters by 2015, representing approximately half of all U.S. electric customers.[352] Figure A.36 illustrates state-level deployments of AMI by 2015. States colored dark blue are projected to serve more than 50 percent of electricity customers with AMI, while states in light blue have projected penetration rates of less than 50 percent of electricity end-users. As of September 2011, FERC reported 7.2 million advanced meters were installed using ARRA funds, with an ultimate goal of 15.5 million.[353]

---

345 Neichin G and D Cheng. 2010. *2010 U.S. Smart Grid Vendor Ecosystem: Report on the Companies and Market Dynamics Shaping the Current U.S. Smart Grid Landscape*. Cleantech Group LLC. Accessed May 17, 2012 at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/2010_U.S._Smart_Grid_Vendor_Ecosystem_Report.pdf .
346 FERC 2011a.
347 FERC 2011b.
348 FERC 2011b.
349 EIA 2011a.
350 IEE – Institute for Electric Efficiency. 2011. *Utility Scale Smart Meter Deployments, Plans & Proposals*. Washington, D.C. Accessed March 22, 2012 at http://www.edisonfoundation.net/iee/Documents/SmartMeter_Rollouts_0911.pdf.
351 IEE – Institute for Electric Efficiency. 2012. *Utility Scale Smart Meter Deployments, Plans & Proposals*. Washington, D.C. Accessed May 17, 2012 at http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterRollouts_0512.pdf.
352 IEE 2012.
353 FERC 2011b.

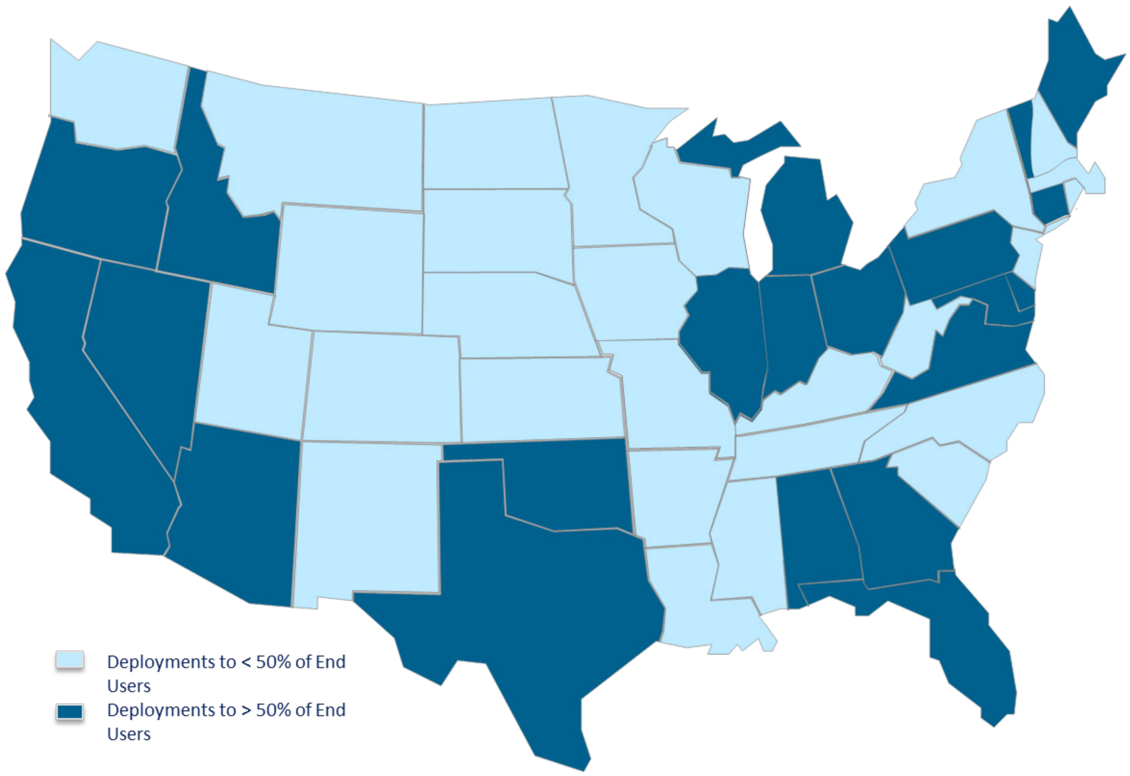



**Figure A.36**. AMI Installments Completed, Started or Planned by 2015[354]

Impacts of ARRA on AMI deployment have been significant. As of September 30, 2012, nearly 11.9 million advanced meters have been installed through the Smart Grid Investment Grant (SGIG) program. Total expenditures on all AMI smart meter installations reported by 92 entities (as of September 30, 2012) amount to approximately $2.0 billion. Further, the SGIG program has co-funded projects supporting communications networks and hardware that enable two-way communications ($542.9 million); the development of information technology hardware, systems, and applications ($389.5 million); and other AMI-related systems ($190.6 million)355. Of the 16.8 million smart meters (based on EIA data) installed to date, more than 11.9 million have been installed through the SGIG program, with an ultimate goal of 15.5 million meters. Counted meter installations using SGIG funding represent meters that are installed and operational.[356] Total expenditures of all AMI installation reported by 96 entities (as of September 30, 2012) amount to almost $3.1 billion, as demonstrated in Table A.17.

---

[354] Adapted from IEE 2012.
[355] DOE – U.S. Department of Energy. 2012. Recovery Act Smart Grid Programs. Washington D.C. Accessed December 12, 2012 at http://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems (Last updated December 11, 2012)
[356]FERC 2011b.

**Table A.17**. Smart Grid Investment Grant Program AMI Asset Investments (September 30, 2012)[357]

| AMI Assets | Quantity | Incurred Cost | Number of Entities Reporting |
|---|---|---|---|
| AMI smart meters | 11,891,852 | $1,918,428,089 | 77 |
| Communications networks and hardware that enable two-way communications | | $ 542,945,603 | 72 |
| IT hardware, systems, and applications that enable AMI features and functionalities | | $389,502,865 | 71 |
| Other AMI related costs | | $190,552,204 | 96 |
| **Total AMI cost** | | $ 3,041,428,761 | 96 |

Many of the SGIG AMI projects have not finished integrating the smart meters with billing and other enterprise systems, but 15 projects representing more than 3.5 million smart meters have reported initial results to DOE for an operational period from April 2011 to March 2012. These projects have reported meter operations cost reductions of between 13 and 77 percent and reductions in vehicle miles driven, fuel consumption, and $CO_2$ emissions of 12 to 59 percent.[358]

As of September 30, 2012, the SGDP program had co-funded the installation of 235,812 advanced meters with total expenditures on AMI and customer systems under the SGDP reaching $89.3 million through September 30, 2012.[359]

### A.12.3.1 Stakeholder Influences

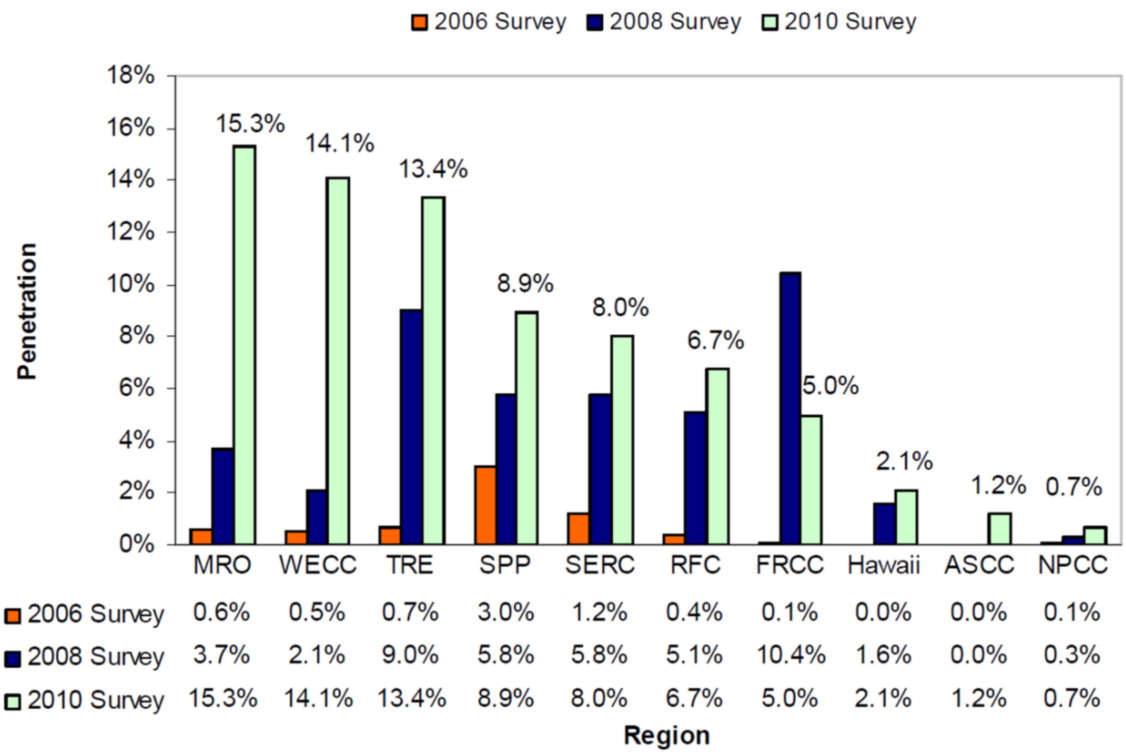
Stakeholders in advanced metering include:

- distribution service providers, to install and recover the investment in advanced meters
- products and services suppliers including IT and communications, to supply the appropriate technology for deployment and use of advanced meters
- local, state, and federal energy policy makers – local regulators will be needed to ensure that distribution-service providers recover their investments in advanced meters
- residential consumers – when coupled with dynamic pricing, will have more control of their energy consumption and will be able to effectively monitor their electric bills
- the financial community – numbers vary for how much it will cost to successfully deploy AMI technology, but it will likely reach several billion dollars.

[357] DOE 2012, last updated December 13, 2012.
[358] DOE – U.S. Department of Energy. 2012b. Operations and Maintenance Savings from Advanced Metering Infrastructure – Initial Results. Washington, D.C. Accessed May 30, 2013 at http://www.smartgrid.gov/document/operations_and_maintenance_savings_advanced_metering_infrastructure_initial_results (undated webpage).
[359] Wang, W. 2013. Personal Communication. Data Compiled from ARRA Recipient's Federal Financial Reports (FFR) SF-435. May 31, 2013.

### A.12.3.2 Regional Influences

In 2010, FERC conducted the third survey for demand response and AMI implementation. Regional results for AMI penetration are presented in Figure A.37 and include penetration rates for surveys completed from 2006-2010, which are presented by NERC region. In 2010, the FRCC was the only region that did not realize growth in AMI penetration over 2008; this is primarily due to reclassification of nearly 400,000 meters in Jacksonville because of the changes to the definition of AMI that are discussed at the beginning of Metric 12.[360] The greatest advancement occurred in the Midwest and Western regions MRO, Western Electricity Coordinating Council (WECC), along with Texas (Texas Reliability Entity). In addition to Figure A.37, projected penetration rates are presented in Figure A.36.




| | MRO | WECC | TRE | SPP | SERC | RFC | FRCC | Hawaii | ASCC | NPCC |
|---|---|---|---|---|---|---|---|---|---|---|
| 2006 Survey | 0.6% | 0.5% | 0.7% | 3.0% | 1.2% | 0.4% | 0.1% | 0.0% | 0.0% | 0.1% |
| 2008 Survey | 3.7% | 2.1% | 9.0% | 5.8% | 5.8% | 5.1% | 10.4% | 1.6% | 0.0% | 0.3% |
| 2010 Survey | 15.3% | 14.1% | 13.4% | 8.9% | 8.0% | 6.7% | 5.0% | 2.1% | 1.2% | 0.7% |

**Figure A.37**. Advanced Meter Penetration by Region: 2006, 2008, and 2010[361]

## A.12.4 Challenges

AMI manufacturers and designers face a myriad of demands from electricity service provider companies and the consumers they represent. Subjects such as weatherproofing, maintenance schedules, memory and data storage all need to be addressed in addition to the development of and adherence to national and state standards for design, communication, and more. These challenges are discussed below.

[360] FERC 2011a.
[361] FERC 2011a.

### A.12.4.1 Technical Challenges

There are a variety of technical considerations involving advanced meters. Although a uniform understanding of minimum qualifications for AMI technology exists, many service providers will find any number of additional qualifications and functions necessary to effectively serve their clients. Because each provider or region has different challenges, including additional "minimum" features or "standard features," AMI systems may prove to be redundant, less cost effective, or even useless in some cases. Interoperability challenges will be faced by providers who install smart meters that are not designed to be integrated with other AMI systems or technologies. Additionally, there may be different opinions between regions on what qualifies as a specific function. For example, PG&E's definition of "tamper flagging capability" may be significantly different from that of Connecticut Light and Power (CL&P). Other considerations such as battery backup, network structure, communication protocols, and encryption also pose technical challenges. However, these challenges are expected to be addressed as continued interconnection standards are developed by the National Institute of Science and Technology.

Cyber security and consumer privacy issues play a critical role in AMI development. Cyber security issues focusing specifically on smart grid expansion include information technology (IT) focus on the combined power system, including communication systems to ensure reliability and security and minimize the risk of cyber-attack on smart grid systems.[362] Additionally, some deployment programs have been delayed due to consumer complaints and refusals to accept smart meters. In northern and central California, for example, a PG&E AMI program has been delayed due to negative consumer opinions of AMI because of perceived security threats and personal privacy issues.[363]

### A.12.4.2 Business and Financial Challenges

Primary business and financial challenges to AMI advancement are associated with the large up-front investment required to deploy AMI. These costs include equipment and labor costs, and cyber security and communications/IT infrastructure investments.

<u>Equipment and Labor Costs</u>: Although ARRA allocated billions of dollars to smart grid technology, there are still significant up-front costs to implement AMI. These include system hardware, software and labor costs associated with deployment and installation of new meters, customer education, IT system integration and data management. A recent study conducted by EPRI concluded that net investment required over the next 20 years in order to implement a national smart grid would be between $338 and $476 billion, including an estimated $16 to $32 billion alone dedicated to AMI.[364]

<u>Cyber Security and Communications/IT Infrastructure</u>: Movement to a digital electric grid requires AMI technologies equipped with security systems to protect against cyber-attack. Current estimates of cyber security cost total 20 percent of IT infrastructure costs for AMI deployment. For a medium-sized

---

[362] NIST – National Institute of Standards and Technology. 2012. *NIST Framework and Roadmap for Smart Grid Interoperability*. Release 2.0, NIST Special Publication 1108R2, Gaithersburg, Maryland. Accessed June 4, 2012 at http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf (undated webpage).

[363] EIA – U.S. Energy Information Administration. 2011b. *Smart Grid Legislative and Regulatory Policies and Case Studies*. Prepared by the U.S. Department of Energy, Washington, D.C. Accessed June 4, 2012 at http://www.eia.gov/analysis/studies/electricity/pdf/smartggrid.pdf (undated webpage).

[364] EPRI – Electric Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed May 16, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.

utility, this could mean initial capital cost of $400,000 and an additional $40,000 on an annual basis for operations and maintenance; these figures rise to $2.2 million and $200,000 for large utilities.[365]

Another smart grid challenge that faces both utilities and consumers is the protection of consumer energy consumption data while still enabling smart grid innovation. The smart grid provides an opportunity to match generation with demand more efficiently than the grid of the past. The challenge is to protect the consumers need for security and privacy while providing the data required to match energy demand with energy generation.[366] NIST dedicated an entire volume to privacy issues in their Smart Grid Cyber Security guidance.[367]

### A.12.5 Metric Recommendations

There are discrepancies in AMI penetration rates based on the data source; private research firms tend to estimate larger deployment numbers than regulatory bodies. Because the EIA only began collecting data on AMI deployments in 2011, it will take a few years for these data to provide consistent information regarding AMI penetration. EIA will begin providing AMI penetration by customer class in 2014 if everything proceeds as planned.

---

[365] EPRI 2011.

[366] DOE – US Department of Energy. 2010. Data Access and Privacy Issues Related to Smart Grid Technologies. Washington, D.C. Accessed November 12, 2012, at http://energy.gov/sites/prod/files/gcprod/documents/Broadband_Report_Data_Privacy_10_5.pdf. (October 2010).

[367] NIST – National Institute of Standards and Technology. 2010. *Guidelines for Smart Grid Cyber Security: Vol. 2: Privacy and the Smart Grid*, NISTIR 7628. Accessed November 9, 2012 at http://csrc.nist.gov/publications/PubsNISTIRs.html#NIST-IR-7628

## A.13 Metric #13: Advanced Measurement Systems

### A.13.1 Introduction and Background

While there are many measurement systems involved in operating the electric power system, for the purposes of this report the term "advanced measurement systems" means the use of PMUs to provide information for wide-area measurements. As the smart grid develops and evolves, other measurements may be added to this metric. At present, however, PMU measurements are the only entry in the field.

PMUs provide real time grid measurements and monitoring of line loading, stability, and available capacity, which in turn allows tighter operating margins, reduces congestion costs, increases electricity transfers, and helps avert cascading outages and blackouts. As of September 2012, the number of Smart Grid Investment Grant (SGIG)-funded installations of PMUs had reached 546 units.[368] As of September 30, 2012, the Smart Grid Demonstration Program (SGDP) program had co-funded the installation of an additional 23 PMUs.[369]

The PMU measurement technology is based on digital processing of waveforms from the power grid, with all the measurements synchronized by means of the global positioning system (GPS), or some timing equivalent of it. Examples are discussed in the new synchrophasor standard of the IEEE, IEEE Std C37.118.1-2011.[370] They include other satellite means, as well as locally distributed signals. The PMU can be given voltage and current signals from the power system, and it produces values for the power, the phase angle, and the frequency at the point of measurement. The values are known collectively as a synchrophasor, which signifies "synchronized phasor." The number of reported values per second is selected from values listed in the latest version of the applicable standard (IEEE C37.118-2011), and may be as high as the power frequency itself, though most installed units report less frequently.

The estimated values that are calculated can give operators a degree of situational awareness that is not otherwise available.[371] The "big picture" of the power system is something that has not been previously available, and the PMU data fills this need. At some point in the future, it is likely that some measure of automatic control will be based on the same information, though at present the information is used by power system operators. Figure A.38 shows PMU data from Oklahoma Gas and Electric, as a storm went through the system one morning in 2011.[372] The operators were monitoring power levels and frequency as well as the voltage angles.

---

[368] DOE – U.S. Department of Energy. 2012. "Deployment Status." In *Recovery Act Smart Grid Program*, SmartGrid.gov, Washington, D.C. Accessed December 12, 2012, at http://www.smartgrid.gov/recovery_act/deployment_status/distribution (Last updated December 11, 2012).

[369] Wang, W. 2013. Personal Communication. *Data Compiled from ARRA Recipient's Federal Financial Reports (FFR) SF-435*. May 31, 2013.

[370] IEEE – Institute of Electrical and Electronics Engineers. 2011. *IEEE Standard C37.118.1-2011 - IEEE Standard for Synchrophasor Measurements for Power Systems*. Accessed July 27, 2012 at http://standards.ieee.org/findstds/standard/C37.118.1-2011.html (undated webpage).

[371] Hauer JF and JG DeSteese. 2007. *Descriptive Model of a Generic WAMS*. PNNL-17138, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 16, 2008 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17138.pdf (undated webpage).

[372] White A and SE Chisholm. 2011. "Synchrophasor Use at OG&E." NASPI Update to the NERC Operating Committee, Accessed July 26, 2012 at https://www.naspi.org/site/Module/Resource/Resource.aspx (undated webpage).

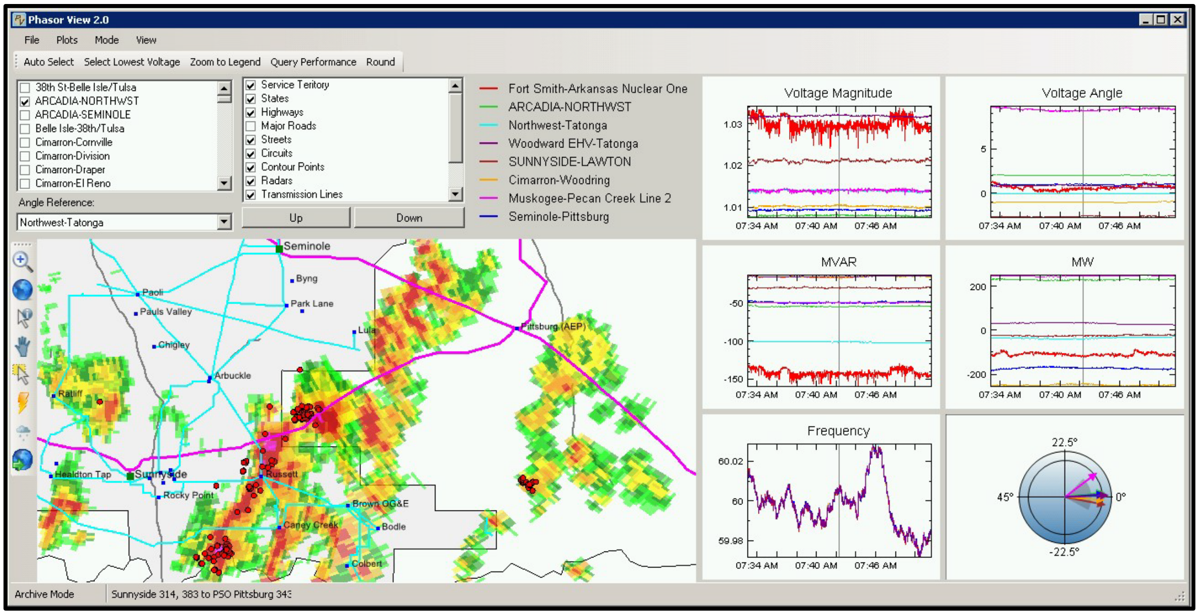



**Figure A.38**. PMU Data Showing Radar Map of a Storm Passing through the Power System of Oklahoma Gas and Electric[373]

A technology similar to PMUs, a frequency monitoring network is also being deployed under the name FNET.[374] In the case of FNET, the signal furnished to the measurement device is the same one used for its power, that is, the outlet at 120 volts. The measurement is GPS synchronized, but only the frequency is measured, using the same internal method as in a PMU. At the moment, FNET data can be used to visualize some aspects of system operation over extremely large areas, and can be used to detect islanding and some other conditions. However, the system at this level is not presently useful for control.

Figure A.39 represents a visualization of the frequency data obtained in the Eastern Interconnection a few seconds after Turkey Point generating station tripped off line in February 2008. It can be seen in Figure A.39 that Florida is operating at a frequency lower than the nominal 60 Hz, and that the under-frequency region, while spreading northward, has not yet crossed Georgia. About two seconds after the time shown here, the under-frequency region had spread into Georgia, but had been partly corrected-for there, and in southern Florida, the frequency had gone back to normal and slightly above normal levels.

[373] White and Chisholm 2011.
[374] Power Information Technology Lab. 2012. *FNET Web Display*. Power Information Technology Lab, University of Tennessee, Knoxville. Accessed July 26, 2012 at http://fnetpublic.utk.edu/ (undated webpage).

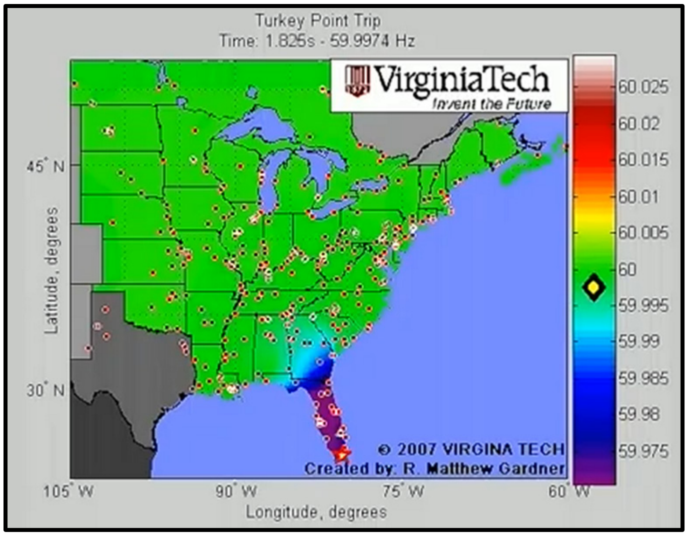



**Figure A.39**. Frequency Data Obtained after Trip of Turkey Point Generating Station

Other data from PMUs is of considerable value in power system operation. This information includes calculations of voltage, current (based on measurements of the waveforms of those parameters) and the real and reactive power, in addition to the phase angle and frequency data, as used in FNET. These quantities are shown in Figure A.38.

Compared to the historical way of collecting data, there are principally two advances in the new technology. First, the sampling is fast enough (a few thousand samples per second is not unusual) to allow phasor quantities to be estimated rapidly. The supervisory control and data acquisition systems that PMUs supplement typically furnished a reading every four seconds. Second, because the estimated quantities are phasors that include both a magnitude and a phase angle, the wide-area monitoring system (WAMS) is able to calculate quantities that are not easily observable. In particular, a parameter known as the power angle can be found between any two locations where PMUs are installed. The power angle is the angle between the phasor voltages in one area and another. It is related to the mechanical angle between the shafts of the generators: the wide-area measurement system is essentially reading out shaft positions that may be thousands of miles apart. With this knowledge, the power flowing from one region of the country to another can be gauged. The inflow into Southern California can be visualized without knowing exactly which power lines are involved. That is a very useful feature when some lines are tripping and operators need to react to prevent a blackout.

It is expected that PMU technology will eventually be present in most grid control systems.[375] At present, the functions of some protective relays are being incorporated into PMUs so they can make further use of the signals they have without replicating the instrument transformers and cabling involved.

DOE has been actively supporting the development of synchrophasor system standards. The new standard, IEEE Standard C37.118-2011, has been under revision by a working group of the IEEE since the 2010 Smart Grid System Report was written, and was approved by the IEEE Standards Association in

[375] Hadley MD, JB McBride, TW Edgar, LR O'Neil, and JD Johnson. 2007. *Securing Wide Area Measurement Systems*. PNNL-17116, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 25, 2010 at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/8-Securing_WAMS.pdf (undated webpage).

December 2011.[376] The standard specifies requirements for synchrophasor measurement, including frequency, rate of change of frequency, and measurement under various operating circumstances.[377]

In summary, WAMS is an evolving technology that can support the following applications:[378]

- real-time observation of system performance
- early detection of large-scale system problems
- real-time determination of transmission capacities
- after-the-fact analysis of system behavior, especially major disturbances
- special tests and measurements, for purposes such as
  - special investigation of system dynamic performance
  - validation and refinement of planning models
  - commissioning or recertification of major control systems
  - calibration and refinement of measurement facilities
- refinement of planning, operation, and control processes essential to best use of transmission assets.

### A.13.2 Description of Metric and Measurable Elements

The measurable element for this metric is:

*(Metric 13) The total number of advanced measurement devices.* The total number of measurement devices that are networked and are providing useful information at the transmission and distribution levels.

### A.13.3 Deployment Trends and Projections

There is no single authority with a definitive list of PMU installations. Thus, the trends and projections presented in this report come from several different sources. Further, due to the many possible applications for the WAMS installations, it is hard to project how many may be needed. A 2007 technical committee report from the NERC indicated that 500 PMUs would be required to adequately monitor the grid.[379]

The number of installed and networked PMUs continues to increase. The NASPI documented 140 networked PMUs installed in the U.S. in 2009. In 2010, the number increased to 166 PMUs. As of September 2012, there were 546 PMUs identified in the US (See the discussion of PMU data in the Regional Influences section of this report).

---

[376] IEEE 2011.
[377] IEEE 2011.
[378] Hauer JF, WA Mittelstadt, KE Martin, JW Burns, and H Lee. 2006. “Best Practices to Improve Power System Dynamic Performance and Reduce Risk of Cascading Blackouts: Monitoring of System Dynamic Performance.” IEEE Power Engineering Society Task Force on Best Practices to Minimize Blackout Risk, IEEE Power Engineering Society, New York.
[379] NERC – North American Electric Reliability Corporation. 2007. *Technology Committee May 1, 2007 Minutes*. Princeton, New Jersey. Accessed September 4, 2008 at http://www.nerc.com/docs/bot/bottc/TC_0507m_Draft.pdf (undated webpage).

The *American Recovery and Reinvestment Act of 2009* (ARRA) SGIG program is expected to further increase PMU installations through 2014. Approximately 13 percent of total SGIG funding is for deployment of synchrophasors and other transmission technologies and systems. This funding covers investment in PMUs, phasor data concentrators, communications networks for acquiring and processing synchrophasor data, and synchrophasor applications software for managing and analyzing data and producing visualization tools, state estimators, and other decision support systems to support both on- and off-line analysis. Table A.18 illustrates the growth of PMU installations between 2010 and 2012 resulting from the SGIG program. DOE reported more than 569 PMUs worth $41.0 million installed by September 30, 2012 for SGIG and SGDP programs.[380,381] Table A.19 presents the 2014 forecast of PMU installations by region and entity. In total, 1,032 PMUs were originally expected to be installed in the U.S. by 2014, led by the Western Electricity Coordinating Council (WECC) with 439 installations, Midwest Independent Transmission System Operator (Midwest ISO) with 165 and Duke Energy Carolinas with 104.[382] The total number of networked PMUs in the U.S., however, has exceeded previous forecasts reaching nearly 1,700 by December 2013.[383]

[380] DOE – U.S. Department of Energy. 2012. SmartGrid.gov. "Electric Transmission System." In *Recovery Act Smart Grid Programs*, Washington D.C. Accessed December 12, 2012 at http://www.smartgrid.gov/recovery_act/deployment_status/transmission (last updated December 11, 2012).

[381] Wang 2013.

[382] Silverstein A. 2011. "NASPI Update and Technology Roadmap." NASPI Update to the NERC Planning and Operating Committee. Accessed July 26, 2012 at https://www.naspi.org/site/Module/Resource/Resource.aspx (last updated April 2011).

[383] Silverstein, A. 2013. *NASPI and Synchrophasor Technology Program.* Presented at NERC OC-PC Meetings. December 2013. Atlanta, GA.

**Table A.18**. Installed and Operational PMUs by Project, Year and Quarter[384]

| PMUs Installed and Operational as of September 30, 2012 | | | | | |
|---|---|---|---|---|---|
| **Project** | **Year** | **Q1** | **Q2** | **Q3** | **Q4** |
| Midwest Energy (Relay Replacement for Knoll Substation) | 2010 | | | | |
| | 2011 | 7 | 7 | 7 | 7 |
| | 2012 | 7 | 7 | 7 | - |
| Midwest Independent Transmission System Operator (Midwest ISO Synchrophasor Deployment Project) | 2010 | | | 0 | 0 |
| | 2011 | 12 | 28 | 28 | 33 |
| | 2012 | 46 | 71 | 97 | - |
| Idaho Power Company (IPC Smart Grid Program) | 2010 | | | | 0 |
| | 2011 | 0 | 0 | 2 | 6 |
| | 2012 | 6 | 8 | 8 | - |
| ISO New England (Synchrophasor Infrastructure and Data Utilization (SIDU) in the ISO New England Transmission Region) | 2010 | | | | 2 |
| | 2011 | 3 | 6 | 7 | 12 |
| | 2012 | 17 | 26 | 34 | - |
| Duke Energy (PMU Deployment in the Carolinas with Communication System Modernization) | 2010 | | | | 20 |
| | 2011 | 20 | 34 | 39 | 52 |
| | 2012 | 69 | 80 | 87 | - |
| American Transmission Company (Phasor Measurement Unit Project) | 2010 | | | | 0 |
| | 2011 | 0 | 0 | 0 | 1 |
| | 2012 | 7 | 26 | 26 | - |
| Florida Power & Light Company (Energy Smart Florida) | 2010 | | | 0 | 7 |
| | 2011 | 7 | 13 | 18 | 26 |
| | 2012 | 34 | 41 | 45 | - |
| PJM Interconnection, LLC (PJM SynchroPhasor Technology Deployment Project) | 2010 | | | 0 | 0 |
| | 2011 | 0 | 0 | 1 | 12 |
| | 2012 | 21 | 25 | 28 | - |
| New York Independent System Operator, Inc. (New York Capacitor/Phasor Measurement Project) | 2010 | | | | 0 |
| | 2011 | 0 | 0 | 0 | 4 |
| | 2012 | 10 | 16 | 23 | - |
| Western Electricity Coordinating Council (Western Interconnection Synchrophasor Program) | 2010 | | | 0 | 0 |
| | 2011 | 16 | 16 | 27 | 30 |
| | 2012 | 47 | 77 | 112 | - |
| Lafayette Consolidated Government (Lafayette Utilities System Smart Grid Project) | 2010 | | | | |
| | 2011 | 0 | 0 | 0 | 26 |
| | 2012 | 26 | 31 | 31 | - |
| Entergy Services, Inc. (Deployment and Integration of Synchro Phasor Technology) | 2010 | | | | |
| | 2011 | | | | |
| | 2012 | | | 37 | - |

[384] DOE 2012. Last updated December 11, 2012.

**Table A.19**. Synchrophasor Projects Forecast for Completion by 2014[385]

| Project Lead | Project Investment (Federal and Private) ($1,000s) | # Transmission Owner Partners | Total PMUs by 2014 |
|---|---|---|---|
| American Transmission Co. | $25,550 | 1 | 45 |
| CCET[(a)] | $27,419 | 3 | 23 |
| Duke Energy Carolinas | $7,856 | 1 | 104 |
| Entergy Services | $9,222 | 1 | 45 |
| Florida Power & Light | $578,963 | 1 | 45 |
| ISO New England | $8,519 | 7 | 39 |
| Midwest Energy | $1,425 | 1 | 7 |
| Midwest ISO | $34,543 | 10 | 165 |
| New York ISO | $75,712 | 8 | 39 |
| PJM | $27,840 | 12 | 81 |
| WECC | $107,780 | 18 | 439 |
| Total | $904,829 | 63 | 1,032 |

(a) CCET = Center for the Commercialization of Electric Technologies

### A.13.3.1 Associated Stakeholders

Advanced measurement systems provide information that can be used by transmission providers and system operators, distribution service providers, and even end-users. In addition, reliability coordinators and the suppliers of grid products and services will have stakes. These stakeholders are affected as follows:

- Transmission providers will assist in the need to understand the business case for deploying advanced measurement technology and properly quantify the benefits of this technology to enhance the reliability of the power system.
- Reliability coordinators and NERC have roles in ensuring grid reliability. They will also need to understand the business case for deployment of the advanced measurement systems.
- Distribution service providers will benefit from better customer relations associated with the enhanced grid reliability.
- End-users (residential, commercial, and industrial) have a stake in anything that could affect power system reliability.

[385] Silverstein 2011.

- Products and services suppliers have two roles. First, they can help educate the industry about the need for advanced systems. Second, they must continue development of the technology and expand useful applications.
- Local, state, and federal energy policy makers all have stakes in ensuring the reliability of the grid, which has been a significant force behind the U.S. economic engine.

### A.13.3.2 Regional Influences

PMU technology is being deployed throughout the world. There are differences in some of these implementations that might affect the applications of advanced measurement systems, sometimes at a regional level. The existence of the new IEEE PMU standard (IEEE C37.118.1) should reduce the effect of such implementation influences in the U.S.; nevertheless, the regional influence can be detected in the applications of the technology.

Figure A.40 shows the existing PMU deployment locations in North America as of March 2012. The figure identifies PMUs (including those installed but not networked), networked PMUs, and aggregators. Based on the data underlying Figure A.40 and updated data for the ERCOT collected from Adams et al. (2012), the number of PMUs was estimated at 274 for the Eastern Interconnection, 17 for ERCOT and 91 for the WECC.[386]

[386] Adams J, P Shrestha, J Balance, and P Palayam. 2012. "Event Analysis Using Phasor Data." *Proceedings in the North American Synchro Phasor Initiative Meeting*, June 5-6, 2012, Denver, Colorado. Accessed July 25, 2012 at https://www.naspi.org/site/Module/Meeting/Reports/SubReports/workgroup.aspx.

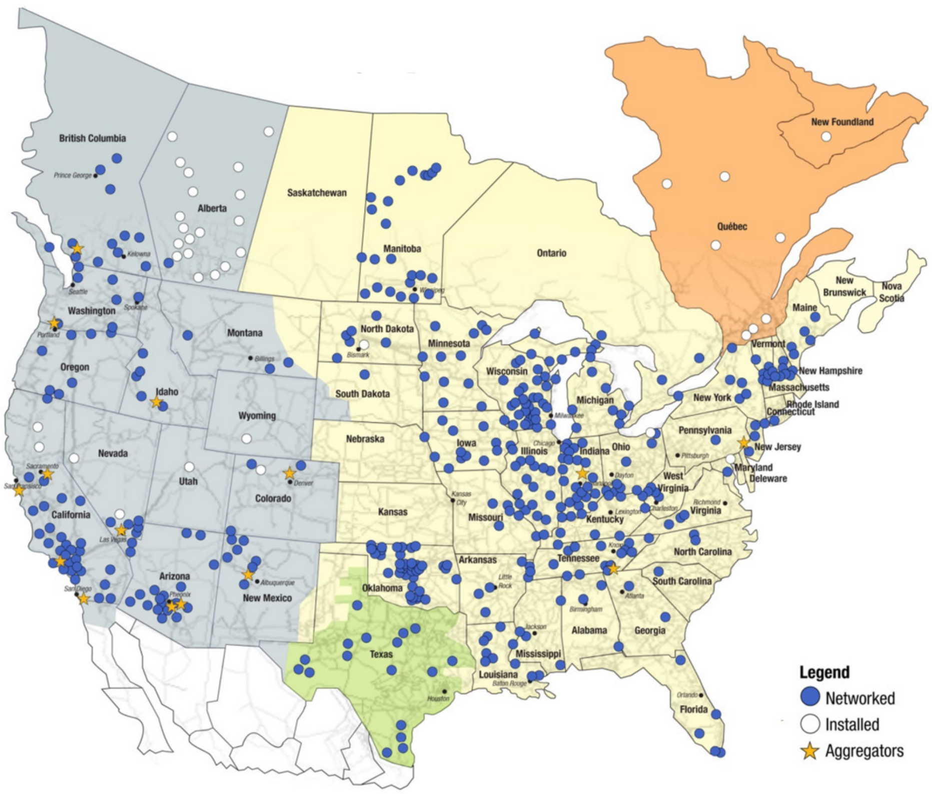



**Figure A.40**. Phasor Measurement Units in the North American Power Grid, March, 2012[387]

Electric-grid data sharing has been significantly increased due to the signing of nondisclosure agreements in the WECC. The Western Interconnection Synchrophasor Program (WISP), which was established in the WECC, has been a stimulus for the effort to get participation from all PMU owners.[388] Under DOE's SGIG program, the WISP[389] will deploy 250 to 350 PMUs using a private wide-area network backbone for communications to phasor data concentrators. The purpose of the WISP project is to use synchrophasor technology to enable smart grid functionality in the WECC. The WISP project will include real-time and off-line applications for the following functions: situational awareness, system performance analysis, model validation, real-time control, and protection and system restoration functionality.

Real-time grid synchronization measurements can provide essential data for system operators that can help increase both system reliability and power quality. Data can also be used to help manage power systems, control load and implement wide-area management systems. Data from Western

[387] EIA – U.S. Energy Information Administration. 2012. *New Technology Can Improve Electric Power System Efficiency and Reliability*. Washington, D.C. Accessed July 25, 2012 at http://www.eia.gov/todayinenergy/detail.cfm?id=5630# (last updated March 30, 2012).

[388] NERC – North American Electric Reliability Corporation. 2010. "Data-Sharing Agreement Executed as Part of the North American Synchrophasor Initiative." Press Release, North American Electric Reliability Corporation, Princeton, New Jersey. Accessed August 2012 in archived press releases, at http://www.nerc.com/news_pr.php?npr=643 (last updated October 20, 2010).

[389] U.S. Department of Energy. 2013. *Western Interconnection Synchrophasor Program.* Washington, D.C. Accessed July 10, 2014 at http://www.smartgrid.gov/project/western_electricity_coordinating_council_western_interconnection_synchrophasor_program (undated webpage).

Interconnection PMUs were instrumental in the investigation of the September 8, 2011, blackout that affected large portions of the Southwestern U.S.[390]

### A.13.4 Challenges to Deployment

The primary challenge to deployment is economics. The business case must be made that advanced measurement technologies provide benefits that justify their cost. While the goal of system operation without major interruptions has remained elusive, it can be argued (by those regulators who must approve rate increases to cover new expenditures) that it is nearly achieved, and that further spending on this goal is not warranted.

The cost of deployment includes not only the capital cost of the hardware, but also the need to install the necessary high-voltage measurement equipment, the networking infrastructure, and the data system. In addition, there are interoperability and data-sharing issues. Applications such as improved visualization tools and other decision-support systems are only under development and not yet routine and that fact does not strongly support the business case.

The secondary challenge to deployment is the confidential nature of the data. Data describing system state and operation are considered sensitive by system owners and operators, and yet these data are required for reliability purposes, wide-area visualization, and research. To further these causes, NASPI continues to involve more utilities in real-time data sharing and has developed a nondisclosure agreement requirement for continued data access to monitoring and visualization tools.

#### A.13.4.1 Technical Challenges

Important technical challenges to deployment include:

- the need for new measurement equipment, and new communication and networking infrastructure
- the development of improved applications such as smart grid functions, stability algorithms, and visualization tools[391, 392]
- the need to overcome reluctance to share data among utilities and others
- the development of new interoperability standards—such standards are an active area at the National Institute of Standards and Technology.

#### A.13.4.2 Business and Financial Challenges

While much progress has been made to integrate phasor data, software, and tools into reliability and electricity service provider settings, there remain challenges to implementation at the research, planning, and operational levels:

- moving from a small-scale research environment to a full-scale commercial deployment

[390] Cummings B. 2012. "Constructing the Sequence of Events and Simulating the Blackout using Phasor Data." Presented at the NASPI workshop on June 6, 2012, Denver CO.
[391] Weekes and Walker 2007.
[392] Spiegel L, S Lee, and M Deming. 2007. *Review of Research Projects for Managing Electric Transmission Uncertainty*. Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop, August 20, 2007, Irwindale, California.

- operating the grid more reliably using phasor visualization tools
- broad integration of phasor data into operations, planning, and maintenance of the grid
- data storage—how much and why?
- communication issues such as speed, latency, and capacity
- transferring large volumes of synchrophasor measurements from distributed phasor data concentrators to application servers
- real-time software development
- benchmarking and validation of models
- off-line analysis
- historian capabilities.

### A.13.5 Metric Recommendations

The Advanced Measurement Systems metric presently emphasizes wide-area measurements; however, consideration could be given to distribution sensor systems. As the smart grid becomes a reality, it will depend increasingly on measurements made in the distribution system. That part of the system is practically unmonitored at present, yet it is the origin of the outages experienced by most people. Improved control and monitoring aimed at such problems as self-healing and improved power quality will depend on new low-voltage sensors, many of which are now being developed with SGIG funding. A revised metric would allow tracking of such developments.

There are two potential metrics that could be helpful in describing progress in Advanced Measurement Systems:

*(Metric 13.b) The percentage of substations with equipment or feeders possessing advanced measurement technology.*

*(Metric 13.c) The number of applications supported by these various measurement technologies.*

These metrics would require some development. For example, in the case of a substation with advanced measurement technology, there are discrepancies in what could count as advanced and in what could count as measurement technology.

# A.14 Metric #14: Capacity Factors

## A.14.1 Introduction and Background

A capacity factor is the fraction of energy that is generated by, or delivered through, a piece of power system equipment during some interval (actual energy delivery), compared to the amount of energy that could have been generated or delivered had the equipment operated at its design or nameplate capacity over the same period (theoretical energy delivery). In principle, a capacity factor is readily understood and measured for many types of transmission and distribution (T&D) equipment, including power generators, transformers and T&D lines. A capacity factor of zero means that equipment was unused during an interval, while a capacity factor of 100 percent means that the equipment was, on average, used at its rated capacity throughout an interval. A capacity factor over 100 percent means that the equipment was overloaded, possibly indicating unsustainable or even dangerous operating conditions. The capacity factor is, therefore, a useful indicator of both strain on, and efficient utilization of, grid equipment. In general, the capacity factor over a short interval (peak capacity factor) indicates how well a system or a particular piece of equipment has safely met demand, while the capacity factor over a long interval (average capacity factor) is an indicator of how efficiently a piece of equipment has been used over that interval.

Consider the traditional approaches to managing the capacity factor: if a transmission circuit becomes inadequate, a new circuit is built, or the circuit is reconductored to increase the corridor's design capacity. If electrical load grows, new centralized generating plants are constructed. If you install an on-demand electric water heater in your home, you and your electricity service provider should consider whether your home's distribution transformer might require replacement. While these approaches are effective for managing peak capacity factors and maintaining safe operating margins, they are often insufficient to properly manage average capacity factors and to ensure efficient system operations.

One key objective of a smart grid is to defer or eliminate the installation of new infrastructure, thus achieving more energy production and transmission using existing equipment. This is done primarily through increasing the capacity factors of existing equipment in a safe and reliable manner. Several smart grid development opportunities have the potential to shift capacity factors either up or down, allowing these developments to be monitored, at least in aggregate, by tracking their related capacity factors. Intelligent controllers might permit an electricity service provider to safely operate close to the operational boundaries of installed grid infrastructure. This can occur by automatically recognizing and mitigating high-stress conditions on the grid and reacting dynamically to conditions that impact the total carrying capacity of individual grid components.

The degree to which the U.S. has recently embraced renewable energy further highlights the importance of this metric. Renewable generation sources, such as wind and solar, are inherently intermittent, with peak capacities approaching an order of magnitude greater than expected average output. Figure A.41 highlights this issue for wind, which is generally considered to be the most highly variable renewable resource. This figure shows the difference between the peak and expected capacities for installed wind generation resources out to 2021. With economic investments and return driven by peak and expected generation, respectively, a low capacity factor and any technologies that can be used to raise it will play an important role driving the economics of the smart grid.

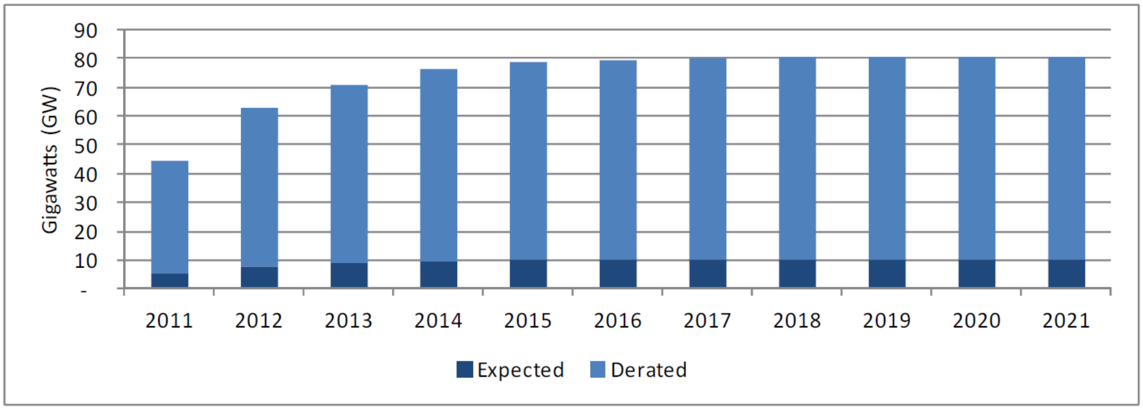



**Figure A.41**. Projected Total Installed Wind Capacity and Expected Average Available Capacity [393]

As this new intermittent generating capacity is introduced to the power grid, the system's annual capacity factor would likely be reduced. Smart grid components (e.g., plug-in electric vehicle integration, energy storage technologies) can be used in the management of these intermittent resources, thus dampening their impact on capacity factors.

Understanding regional and local capacity factors is also important. For example, when taken in aggregate, the growth over the next ten years of wind generation shown in Figure A.41 does not show the full picture of the coming challenges. If one considers that the vast majority of potential growth shown in Figure A.42 is in only three regions, and that the region with the highest potential growth (ERCOT) is also one that issued seven energy emergency alerts due to high summer peak capacity factors in 2011, it becomes clear how this information can be useful in efficiently directing investment and for highlighting those areas that stand to benefit the most from smart grid technologies.[394]

[393] NERC – North American Electric Reliability Corporation. 2011a. *2011 Long-Term Reliability Assessment*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/files/2011LTRA_Final.pdf (undated webpage).

[394] ERCOT – Electric Reliability Council of Texas. 2011. *ERCOT in Level 1 Emergency; Consumers Asked to Conserve 3-7 p.m. Today*. News Release dated August 24, 2011, Electric Reliability Council of Texas, Austin, Texas. Accessed June 13, 2012 at http://www.ercot.com/news/press_releases/show/429 (last updated August 24, 2011).

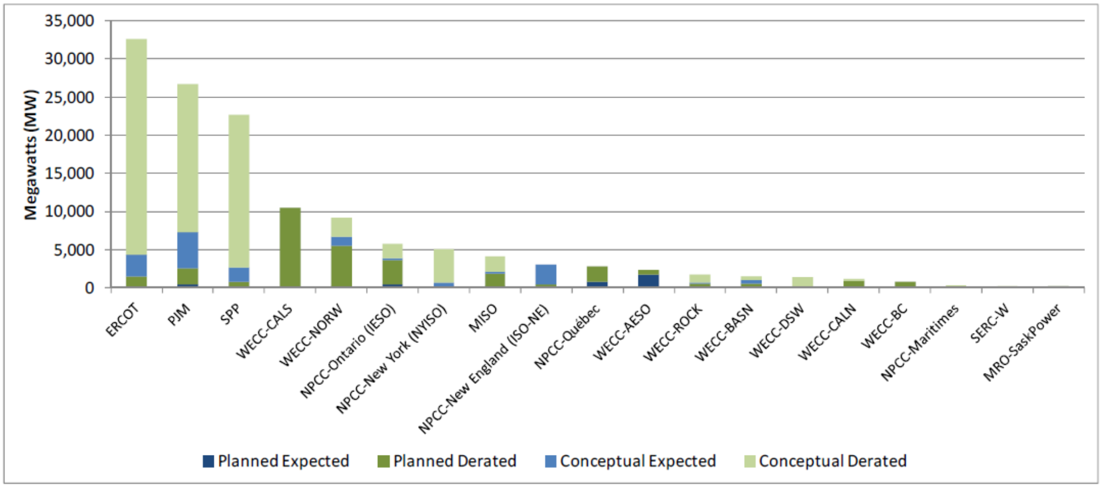



**Figure A.42**. Distribution by Control Area of Potential Wind Capacity Expansion[395]

In addition to variable generation affecting the capacity factors of T&D equipment, demand patterns and how they might be affected by the smart grid also play an important role. Successful implementation of DG and storage resources could, in principle, reduce the fluctuations experienced by the T&D system by shaving peaks and filling troughs in demand. By examining the capacity factors in regions with high DG and storage penetration, this metric can provide useful information on how successfully such equipment has been integrated. This knowledge can, in turn, be used to drive investment or to tease out the characteristics of successful projects. By flattening load profiles, a smart grid could make better use of the available electricity infrastructure capacity. Load profiles that have large diurnal and seasonal peaks stress grid infrastructure and are inefficient with respect to both cost and energy. Energy inefficiency in transmission lines increases with the square of the current, so if a daytime spike in demand is twice the daily average, the losses increase four times.

In a similar vein, consumer trends will also affect capacity factors. Growing demand for consumer electronics and the possibility that our consumption of fossil fuels for transport will be displaced by plug-in electric vehicles present new challenges—and perhaps opportunities—for the management of capacity factors within our distribution systems. Again, the impact of such consumption changes will be reflected in and can be tracked by the capacity factors of the utility gird.

Another key element of the utility grid that can be reflected in capacity factors is grid security and reliability. Transmission systems are run based on an "N-1" contingency, meaning one line could be lost and the system would remain stable, which increases reliability but reduces capacity loading and increases cost. Though the smart grid would not do away with the necessity for the N-1 contingency, managing the grid such that peak capacity factors were kept low and average capacity factors high would allow for a reduced safety margin. With smart grid technologies deployed effectively, the reduced safety margins would lower redundancy while at the same time maintaining security and reliability. As one can see from Figure A.43, reliability is by far the primary driver of grid investment, driving 84 percent of the 38,900 miles of 100 kV transmission lines forecast to be built over the next 10 years.[396]

[395] NERC 2011a.
[396] NERC 2011a.

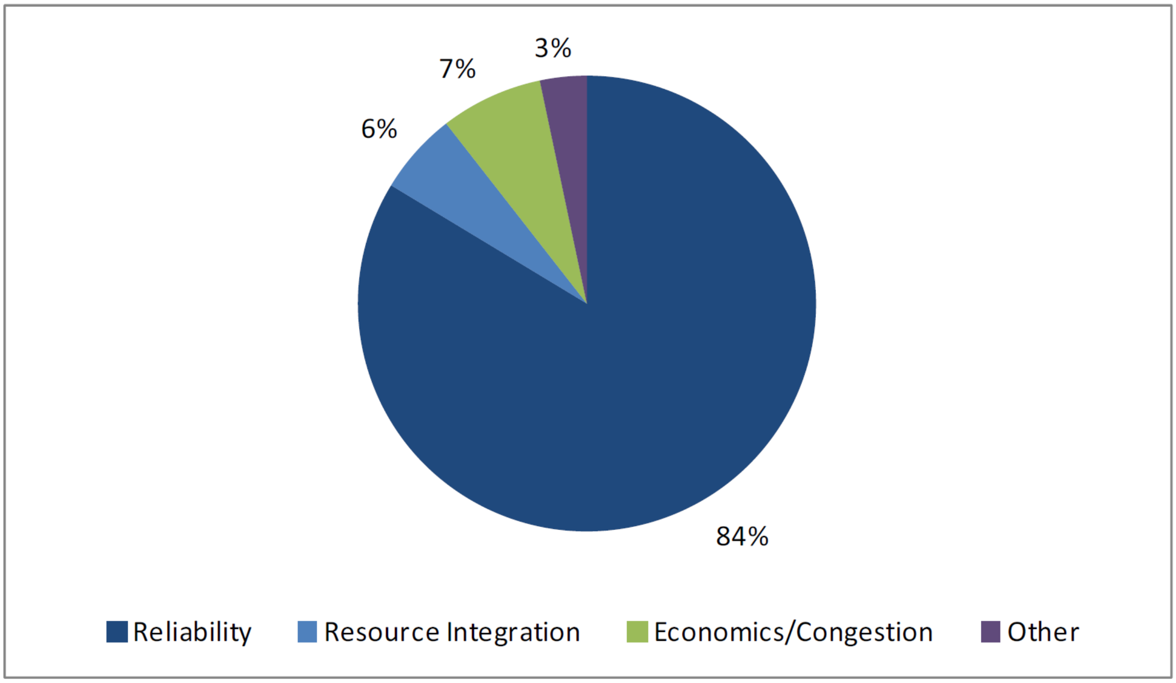



**Figure A.43**. Drivers for New Transmission Investment[397]

## A.14.2 Description of the Metric and Measurable Elements

This section defines specific measurements that can be used to find the capacity factors (CF) across the power grid's generation, transmission, and distribution systems, as well as across major types of power-grid equipment, including generators, conductors, and transformers. Three measurements that pair generation with generators, transmission with conductors, and the distribution system with transformers are proposed. For each of these pairings, both average and peak capacity-factor measurements are calculated.

*(Metric 14.a) Yearly average and peak generation capacity factor (%).* The yearly average capacity factor of the nation's entire generator population should be estimated (see Equation 14.a).

To calculate this metric, two numbers are required. The first is the total aggregate nameplate or design capacity of all generators in place for the year in question. Next, the total energy generated over the course of the year is found. This number is divided by the aggregate capacity and the number of hours in the period (8,760 in the case of a year) to find the annual average capacity factor. This equation can be easily modified to find the average capacity factor over shorter periods by adjusting the length of time for which data are collected. For longer periods this metric can be used to answer the question, "How efficiently did we use our installed generation capacity over the period in question?" As the time over which total resource use (megawatt-hours) is measured decreases, this metric can help answer the question, "How close did the nation come last year to exceeding its generation capacity?"

[397] NERC 2011a.

$$CF_{\text{Generation}}(\%) = \frac{\sum_{\text{All Generators}} \sum_{\text{Year}} \text{Generated Energy (MWh)}}{8760\,(\text{hours}) * \sum_{\text{All Generators}} \textit{Generator Power Rating}\,(MW)} * 100\,(\%) \tag{14.a}$$

*(Metric 14.b) Yearly average and average peak capacity factors for a typical mile of transmission line (%-mile per mile).* Capacity factor of the nation's transmission lines should be estimated, the result being weighted to account for transmission line distances (see Equations 14.b1 [per line] and 14.b2 [distance weighted]).

The transmission capacity factors are calculated by finding the total rated capacity of each transmission line and the actual energy delivered over some period (typically a year); (see Equation 14.b1). The product of the capacity factor and length (in miles) for each transmission line can then be summed and divided by the total length of all transmission lines to get a weighted average capacity factor per mile of transmission line, Equation 14.b2.

$$CF_{\text{Trans. Line}}(\%) = \frac{\sum_{\text{Year}} \text{Transmitted Energy (MWh)}}{8760\,(\text{hours}) * \sum \text{Line Power Rating (MW)}} * 100\,(\%) \tag{14.b1}$$

$$CF_{\text{Per Mile Trans. Line}}(\%) = \frac{\sum_{\text{All Lines}} \text{Line Distance (miles)} * CF_{\text{Trans. Line}}(\%)}{\sum_{\text{All Lines}} \text{Line Distance (miles)}} \tag{14.b2}$$

*(Metric 14.c) Yearly average and average peak distribution-transformer capacity factor (%).* Estimate of the average capacity factor of the nation's distribution transformers over the year (see Equation 14.c).

Similar to the capacity factor metric for generation, the transformer capacity factor metric is found by taking the sum of all transformer energy over some period and dividing it by the aggregate of the rating for each transformer in question.

$$CF_{\text{Dist. Xfmr}}(\%) = \frac{\sum_{\text{All Xfmrs.}} \sum_{\text{Year}} \text{Xfmr. Energy (MWh)}}{8760\,(\text{hours}) * \sum_{\text{All Xfmrs.}} \text{Xfmr. Ratings (MW)}} * 100\,(\%) \tag{14.c}$$

### A.14.3 Deployment Trends and Projections

Data useful for metric measurement 14.a are collected and forecast annually by the NERC.[398] NERC data measure peak summer demand and generation capacity, peak winter demand and generation capacity, and yearly annual generation for each major NERC region. Published data included measurements from 1989 through 2009, and projected estimates through 2019. Table A.20 summarizes

---

398 NERC – North American Electric Reliability Corporation. 2011b. *2011 Reports (with 2010 Actuals)*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/page.php?cid=4|38|41 (undated webpage).

the resulting Metric 14.a capacity factor measurements for three years: 2007, 2009, and 2011, the most recent year for which measured data were available. On average, less than half of the nation's generation capacity is now used, but less than 25 percent of the nation's total generation capacity remains unused during summer peaks. If properly applied, smart grid technologies could potentially lead to increased asset utilization over time, thus increasing overall capacity factors while maintaining safe peak capacity factors without new investment in generation capacity.

**Table A.20**. NERC Actual and Projected Peak Demands and Generation Capacities and Calculated Capacity Factors[399]

| | 2007 Actual | 2009 Actual | 2011 Actual | 2013 Projected |
|---|---|---|---|---|
| Summer Peak Demand (megawatts [MW]) | 866,229 | 755,614 | 843,072 | 857,161 |
| Summer Generation Capacity (MW) | 1,071,459 | 1,066,017 | 1,170,432 | 1,252,369 |
| Capacity Factor 14.a, Peak Summer (%) | 81% | 78% | 72% | 68% |
| Winter Peak Demand (MW) | 736,418 | 644,869 | 745,893 | 763,781 |
| Winter Generation Capacity (MW) | 1,100,005 | 1,092,080 | 1,202,934 | 1,216,142 |
| Capacity Factor 14.a Peak Winter (%) | 67% | 68% | 62% | 63% |
| Yearly Energy Consumed by Load (gigawatt-hours) | 4,461,248 | 4,543,722 | 4,555,185 | 4,617,292 |
| Capacity Factor 14.a, Annual (%) | 48% | 49% | 44% | 42% |

Some trends can be observed in data presented in Figure A.44, which presents actual capacity factor data back to 1989 and forecast data out to 2022. According to NERC data, the U.S. grew closer to its generation limits before peaking in the summer of 1999 with a peak capacity factor of 90 percent; (the winter peak of 78 percent occurred in the proceeding and following winters). The trend has been steadily downward since this peak, reaching a summer peak of 72 percent and annual capacity factor of 44 percent in 2011, with only a small uptick in 2006 and 2007. The downward trend is expected to continue until 2013, after which a slow annual increase is projected out to 2019.

[399] NERC 2011b.

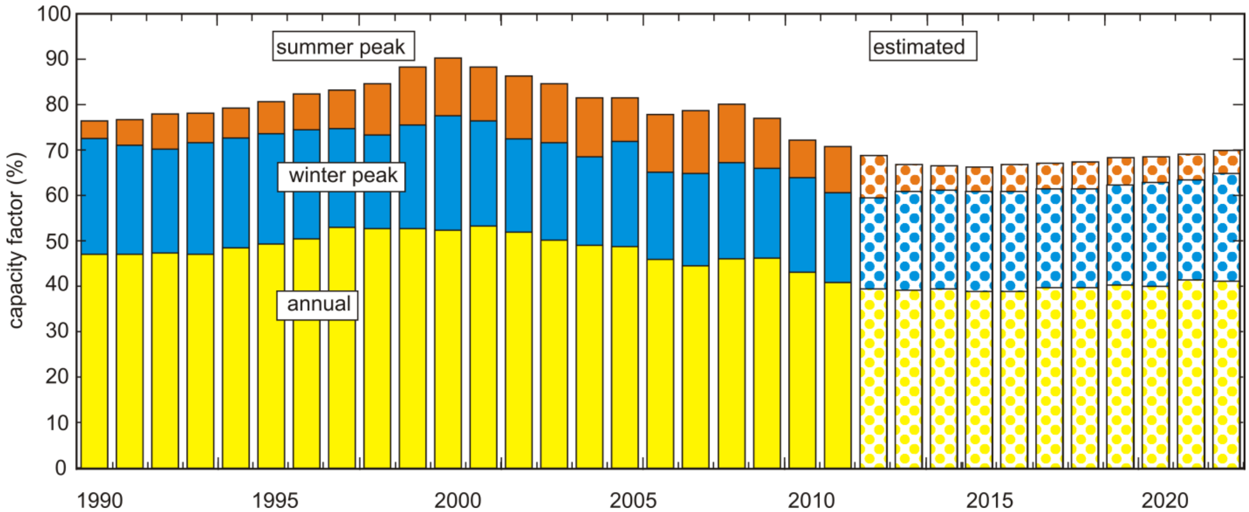



**Figure A.44**. 1990 to 2021 Measured and Predicted Peak Summer, Peak Winter, and Yearly Average Generation Capacity Factors[400]

Capacity factors have declined since the 2010 SGSR was published primarily due to the recent economic downturn. Load dropped as business activity declined between 2006 and 2009. Figure A.45 shows that demand growth has picked up slightly since then but has yet to achieve its previous peak. This decline has left a similar amount of generation to serve less load, thus reducing the capacity factor. Data of this quality were not found for the other two metrics (14.b and 14.c.), capacity factors that would indicate the status of the nation's T&D systems.

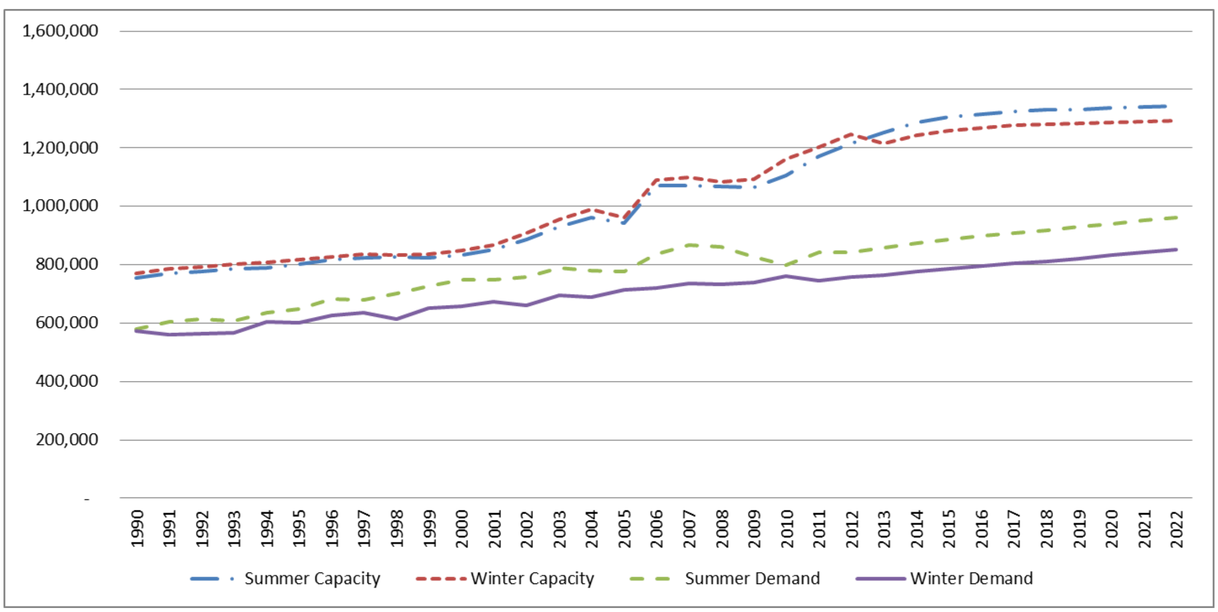



**Figure A.45**. 1990 to 2021 Historical and Projected Peak Demand and Capacity[401]

---

[400] NERC 2011b.

[401] NERC – North American Electric Reliability Corporation. 2011c. *Assessment & Trends: Electricity Supply & Demand 2011*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/page.php?cid=4|38 (undated webpage).

Policymakers and regulators at the federal and state levels have identified demand-side management as a tool to reduce the need for new peak energy sources. Consequently, energy efficiency and demand response are projected to reduce peak demand growth, as well as defer the need for additional generating capacity. Much of the peak demand reduction will be contributed by just a few sub-regions where programs and policies are in place to drive demand response. The New England independent system operator has a particularly progressive program that includes active auditing and monitoring of energy efficiency resources being installed, with their consequent embedding in load forecasts as demand reductions.

Planning reserve margin is the measure of generation capacity available to meet expected demand in a planning horizon time frame. This technique has been in use by planners for decades as a relative indication of adequacy. Adequate capacity is needed to maintain reliable operation during extreme weather conditions and during unexpected outages. The declining reserve margins present in the U.S. grid imply the capacity factor for generation is declining and could indicate reduced grid reliability and security in the future. Figure A.46 shows this predicted decline in the forecast aggregate U.S. reserve margin between 2011 and 2021.

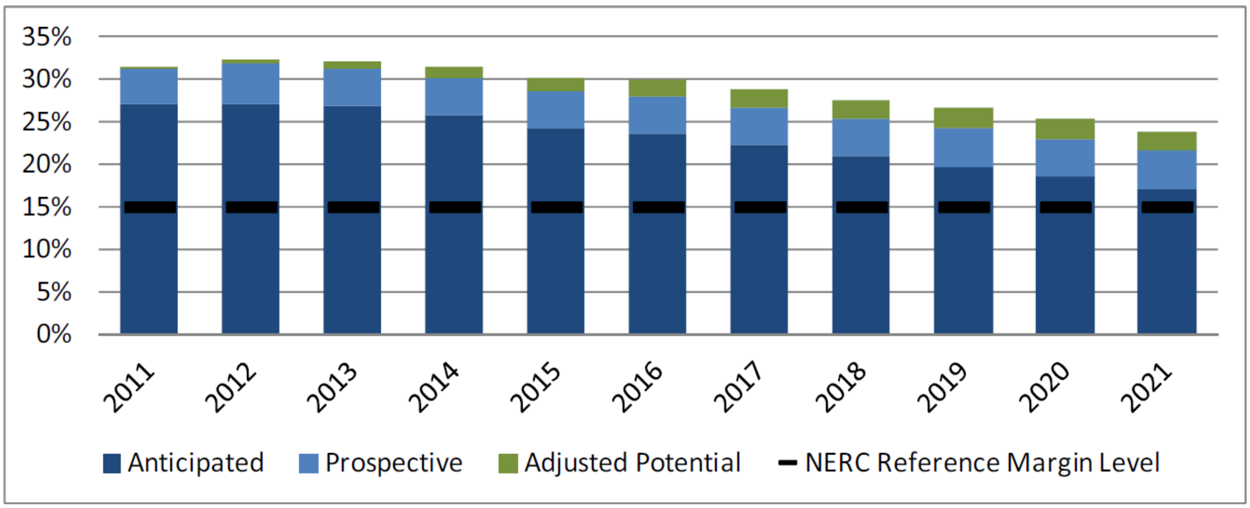



**Figure A.46**. NERC U.S. Summer Peak—Planning Reserve Margin[402]

#### A.14.3.1 Stakeholder Influences

Our nation's electrical grid is regulated mostly on a federal and state-by-state basis, and involves the participation of a very large number of stakeholders. More specifically, the following stakeholder influences were observed:

- policy advocates – Metric 14 is important for identifying a number of trends relevant to policy advocates. The metric helps advocates verify claims that power grid equipment capacities are adequate or inadequate for the anticipated growth of electricity usage. Capacity factor trends also help support smart grid policies that would flatten load profiles or allow operation with smaller operational margins.

[402] NERC 2011a.

- reliability coordinators including NERC – The three measurements of this metric measure generation, transmission, and distribution-transformer margins. Capacity margin information is important for reliability coordinators and system planners to monitor.
- generation and demand wholesale-electricity traders/brokers – Understanding the capacity factor within a marketplace is important for rational participation by market players. Since enhanced information can provide a competitive edge, detailed data are often protected.
- balancing authorities – The ability to balance load and generation is affected by the availability of generation resources and may be limited by transmission constraints that have some reflection in the capacity metric.
- transmission providers – Through Equation 14.b, this metric provides a benchmark for transmission providers concerning their relative practices for loading transmission lines.
- distribution-service providers – Through Equation 14.c, this metric provides distribution-service providers a benchmark concerning their practices of loading provided distribution equipment—transformers, in this case.
- electric-service retailers – This metric provides general information over time about the effects of changes in customer energy usage. Plug-in hybrid electric vehicles, for example, are a type of technology that has the potential to dramatically change the way we use our existing electric distribution system and may have ramifications on the way retailers can supply such electrical load.
- end users – End users should benefit indirectly from the improved reliability that could result from our improved understanding of the adequacy and operational margins built into our grid infrastructure.

### A.14.3.2 Regional Influences

NERC data for regions within the U.S. show some interesting trends. Figure A.48 through Figure A.59, all derived from the 2011 NERC Long-Term Reliability Assessment report,[403] show how capacity factors are expected to change over time in regions outlined in Figure A.47. Though long-term planning is considered to be “inherently uncertain” due, among other reasons, to the impact of economic cycles on demand growth, the charts provide a good indication of likely grid trouble spots and, thus, show where smart grid technologies could have the greatest potential impact.

[403] NERC 2011a.

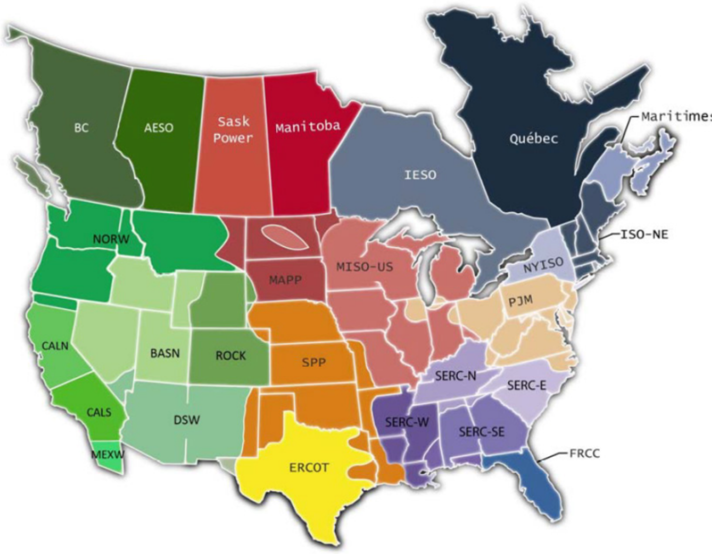



**Figure A.47**. NERC 2011 Long-Term Assessment Area Regions[404]

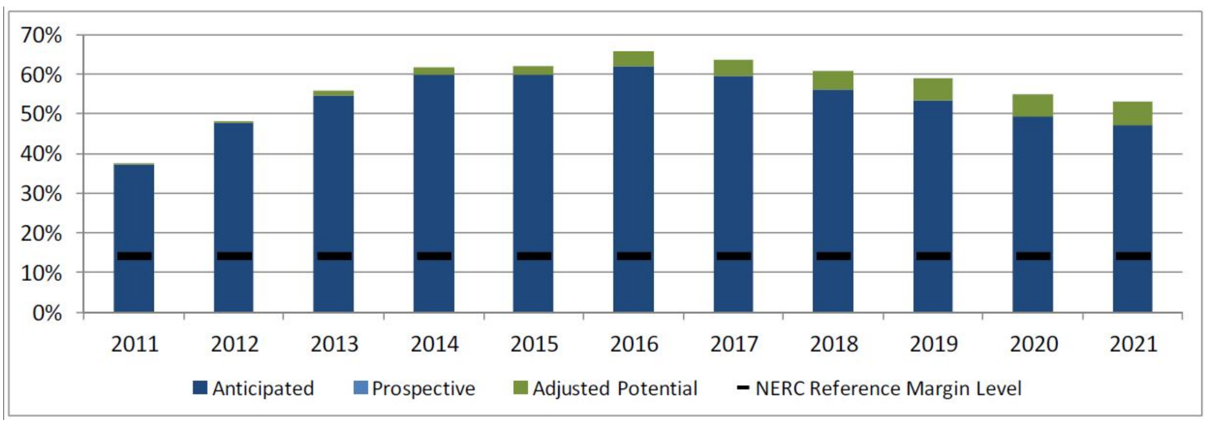



**Figure A.48**. Western Electricity Coordinating Council (WECC) Annual On-Peak Planning Reserve Margins

[404] NERC 2011a.

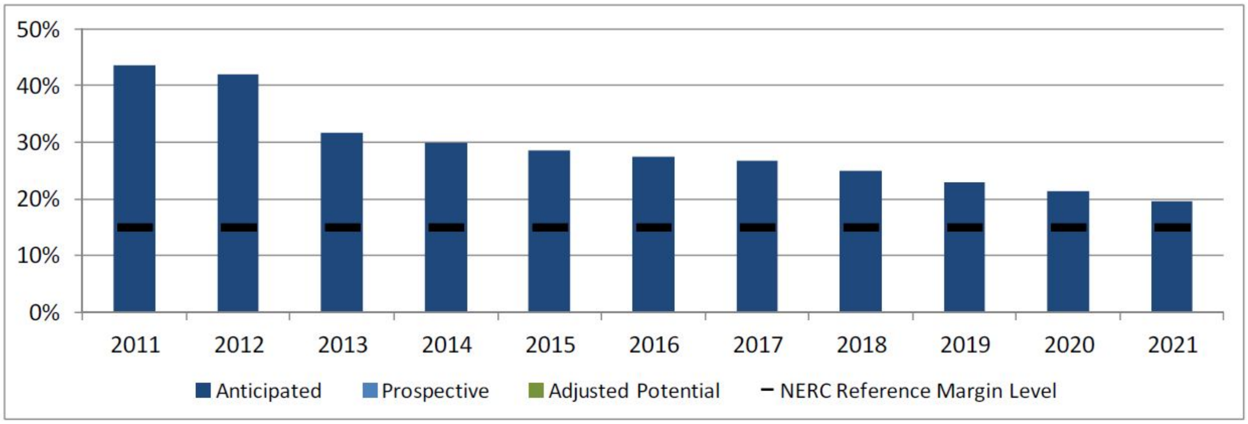



**Figure A.49** Midwest Reliability Organization Mid-Continent Area Power Pool Annual On-Peak Planning Reserve Margins

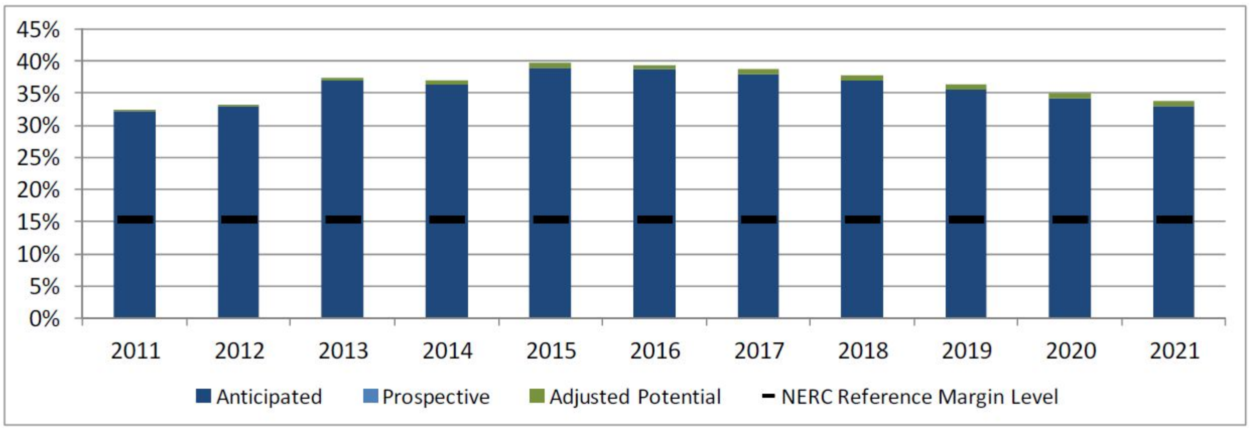



**Figure A.50**. Northeast Power Coordinating Council (NPCC) New York Annual On-Peak Planning Reserve Margins

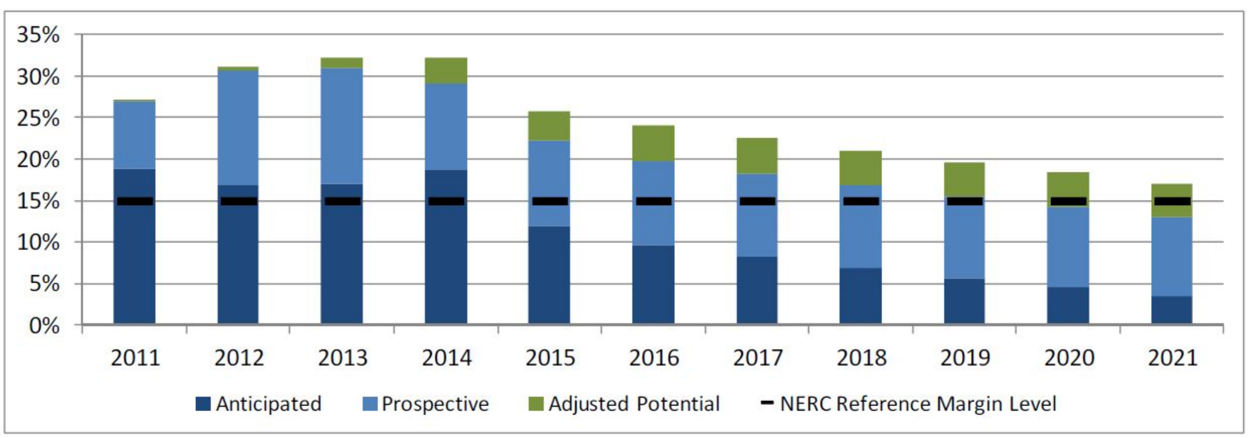



**Figure A.51**. NPCC New England Annual On-Peak Planning Reserve Margins

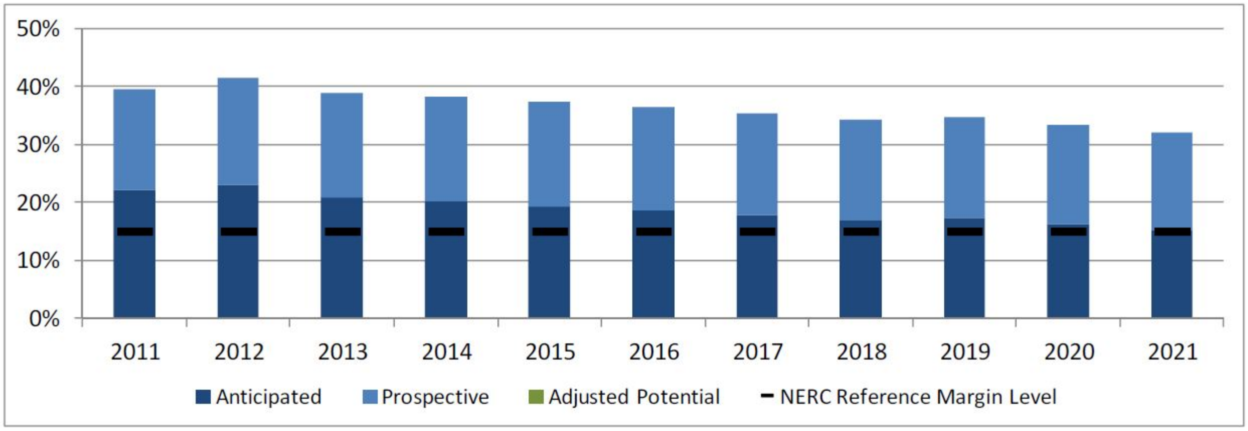



**Figure A.52**. Midwest Independent Transmission System Operator Annual On-Peak Planning Reserve Margins

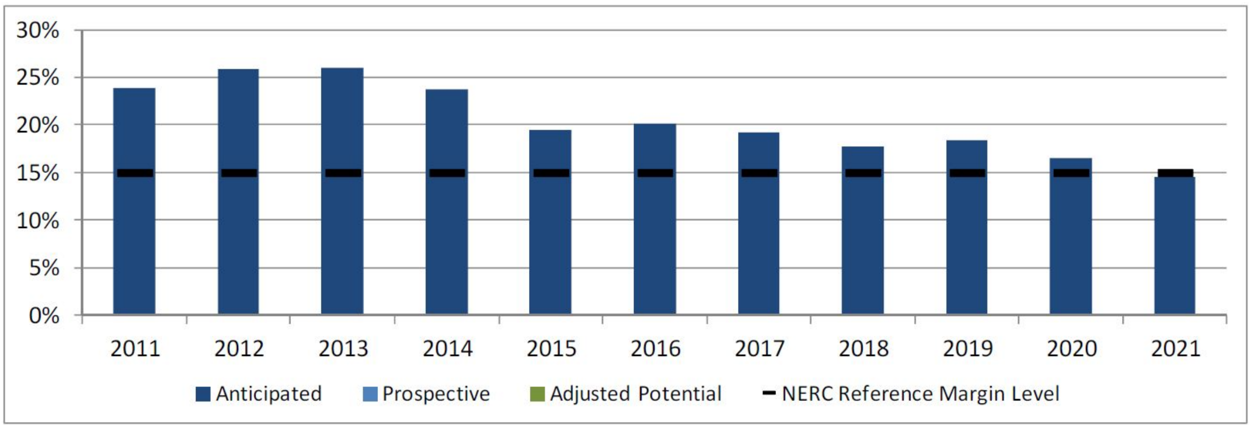



**Figure A.53**. SERC Reliability Corporation (SERC) East Annual On-Peak Planning Reserve Margins

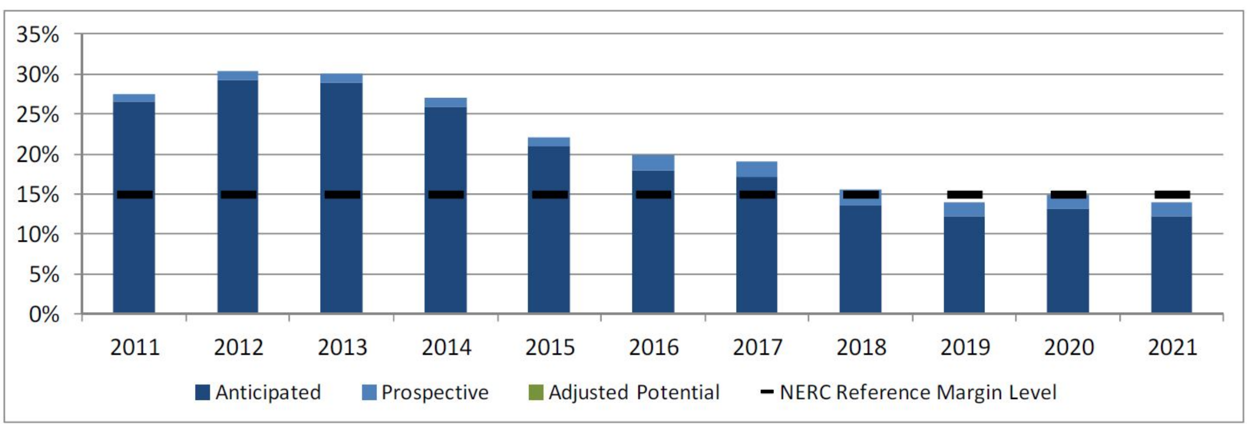



**Figure A.54**. SERC North Annual On-Peak Planning Reserve Margins

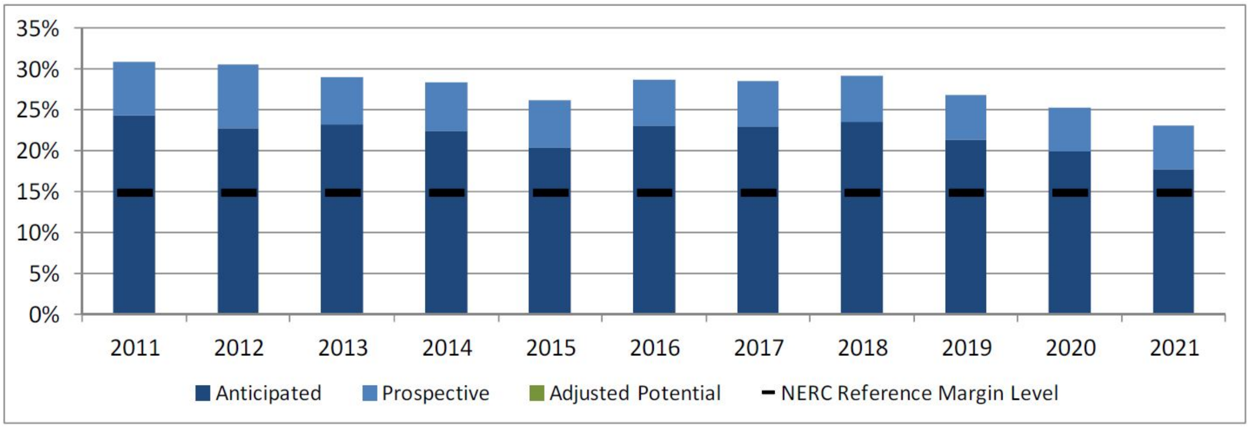



**Figure A.55**. SERC Southeast Annual On-Peak Planning Reserve Margins

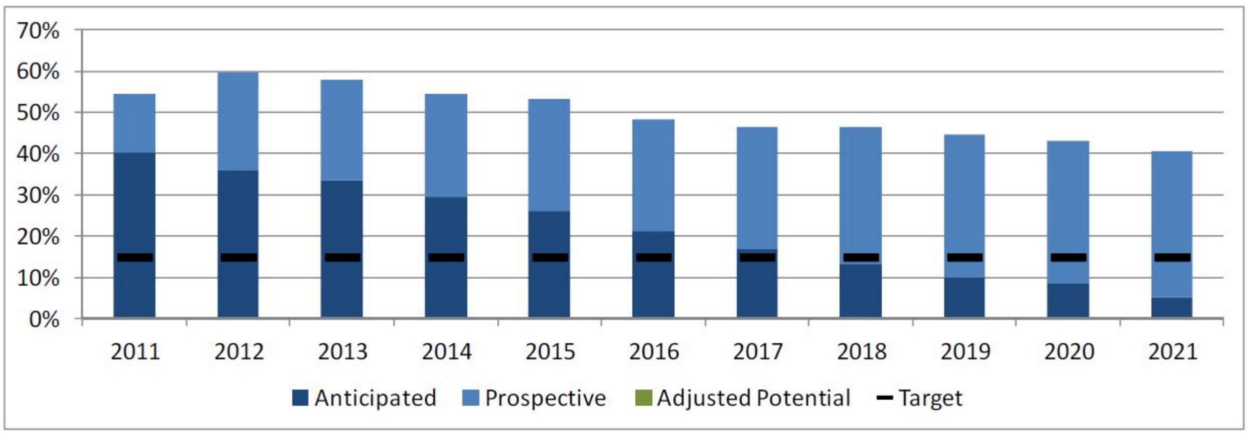



**Figure A.56**. SERC West Annual On-Peak Planning Reserve Margins

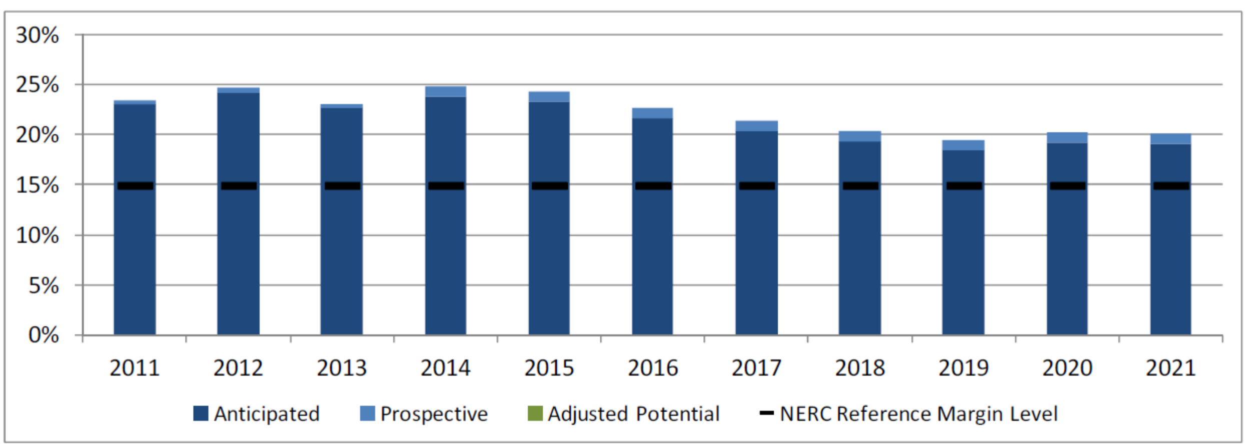



**Figure A.57**. Florida Reliability Coordinating Council Annual On-Peak Planning Reserve Margins

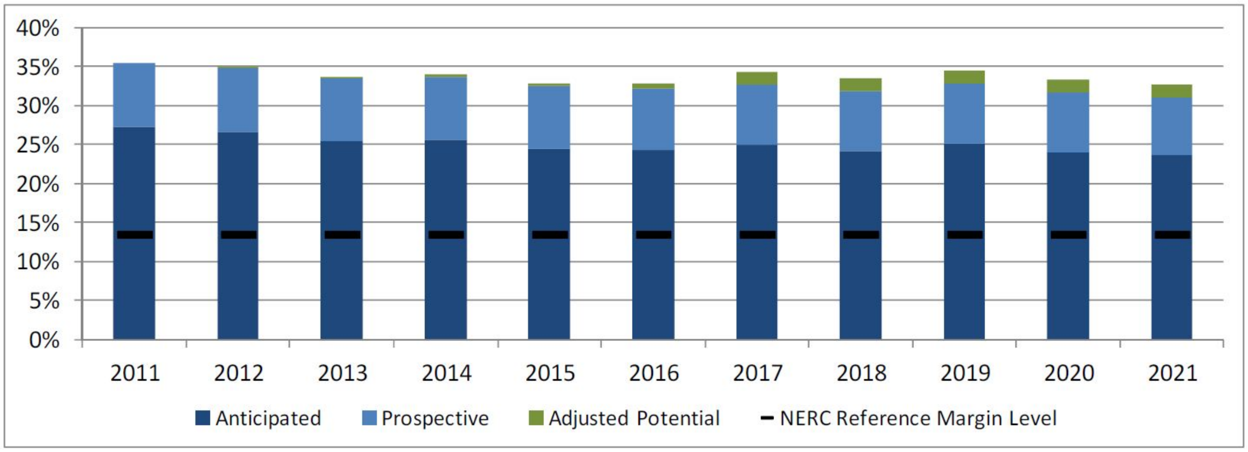



**Figure A.58**. Southwest Power Pool Annual On-Peak Planning Reserve Margins

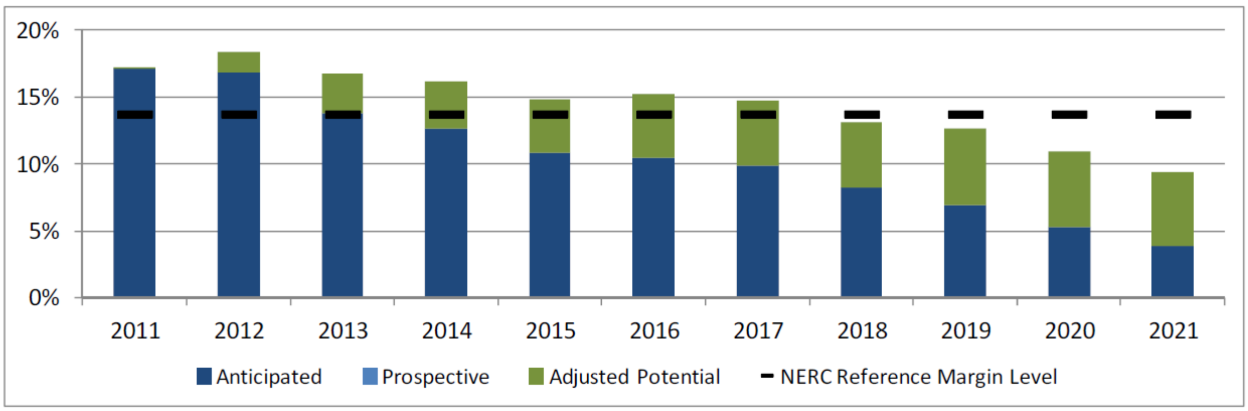



**Figure A.59**. Electric Reliability Council of Texas (ERCOT) Annual On-Peak Planning Reserve Margins

Many different regional factors are reflected in the above charts, from differing reserve margin requirements to aging infrastructure and local regulatory changes. NPCC New England is a good example of a densely developed region with aging T&D infrastructure; both factors will contribute to a declining reserve margin over the next decade. Siting issues due to development density can increase the cost of additional capacity, while aging infrastructure leads to a large amount of equipment capacity that must be retired in the coming decade. ERCOT, on the other hand, shows declining reserve margins due partially to high regional demand growth and changes in regulatory requirements for generation equipment, such as the Cross-State Air Pollution Rule. ERCOT is further hindered by the level of installed wind capacity that can be considered "existing-certain" resources (8.7 percent) and so contribute to reserve margin determinations.[405] Similar location-specific challenges are faced by all regional utility management organizations and should be used to give context to key smart grid metrics such as average and peak capacity factors.

## A.14.4 Challenges

Many technical, business, and policy challenges potentially hinder the use of the capacity factor as a metric of smart grid evolution.

[405] NERC 2011a.

### A.14.4.1 Technical Challenges

Capacity factor values are not typically shared among utilities and regions. The large quantities of equipment at the generation, transmission, and distribution levels will make this metric difficult to track without accepting a statistical-sampling approach for the recommended measurements. Currently, suitable data is only available for generation facilities. Even with a statistical-sampling approach, the level of monitoring required to accurately determine the transmission or transformer capacity factors makes it unlikely that this data will ever be widely gathered and communicated across the grid without some incentive, either economic or regulatory. Even if monitoring equipment is installed on all new projects, data availability will remain low for some time due to the slow pace of changes in power grid infrastructure. In general, it will be challenging to obtain useful measurements with an accuracy that supports a meaningful monitoring of system trends over time using capacity factor measurements.

### A.14.4.2 Business and Financial Challenges

Because the grid spans multiple regions, industries, and functions, it is challenging to obtain the necessary information required to develop accurate capacity factors. In addition, it can be difficult to identify those responsible for coordinating and sharing responsibility for making capacity enhancements. This leads to challenges in creating incentives to invest in smart grid technology that can better manage capacity factors. The lack of financial or regulatory incentives to collect and report the data that are required to develop capacity factors beyond those for generation hinders the development of this metric.

### A.14.4.3 Metric Recommendations

Data were not readily found for measurements using Equations 14.b and 14.c concerning our nation's transmission and distribution transformer infrastructure. It is recommended that samplings be performed to estimate these metric measurements. The inability to use Equations 14.b and 14.c is driven by the fact that there is no information regarding individual transmission-line capacity in a compiled form. No electricity service provider shares data regarding the size and loading of distribution transformers. Without these two pieces of data, these metrics are not calculable and, therefore, are not usable.

Data continuity also presents a challenge for developing capacity factor metrics. Many key data points, even when available, are difficult to track from year to year due to changes in data collection and reporting methodologies. If a specific data point is to be collected or reported in a different way than in previous years, it is important that the body responsible for the data collection and reporting identify what the changes are and how to translate previous year's data in such a way that it is comparable to the current data.

# A.15 Metric #15: Generation, Transmission, and Distribution Efficiency

## A.15.1 Introduction and Background

The generation of electricity from thermal sources is unavoidably inefficient. The efficiency depends on many parameters, but the theoretical maximum value depends only on the values of the highest and lowest temperatures in the system. Expressed in degrees above absolute zero, these values are often close to one another. The best efficiency that can be obtained by a "perfect" machine is given by the difference in temperature divided by the higher temperature:

$$\text{Efficiency} = T_{diff}/T_{high} = 1 - T_{low}/T_{high}$$

If the low and high temperatures are the same, the efficiency is zero. The fraction of total energy that can be extracted from a thermal process was studied by Carnot as long ago as 1824, and the idealized process by which thermal energy is converted into work is known as the Carnot cycle.

Once electricity has been generated, the delivery process is much more efficient, though the large quantity distributed means that even a small loss represents a significant dollar amount. Generation, transmission, and distribution efficiencies are measured by the EIA, and losses are represented in Figure A.60.[406] Generation efficiency is measured in terms of heat rate, or the ratio of delivered electric energy to the chemical energy in the fuel input. Transmission and distribution (T&D) efficiency are measured by the line losses incurred in transporting the energy. The relative importance of these two factors can be judged from Figure A.60. Note that although the energy lost to transmission and distribution is small compared to the Carnot-cycle losses, it is significant, and is worth addressing.

[406] EIA – U.S. Energy Information Administration. 2011. *Annual Energy Review 2010*. DOE/EIA-0384 (2010), Office of Energy Statistics, Washington, D.C. Accessed May 31, 2012 at http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf (undated webpage).

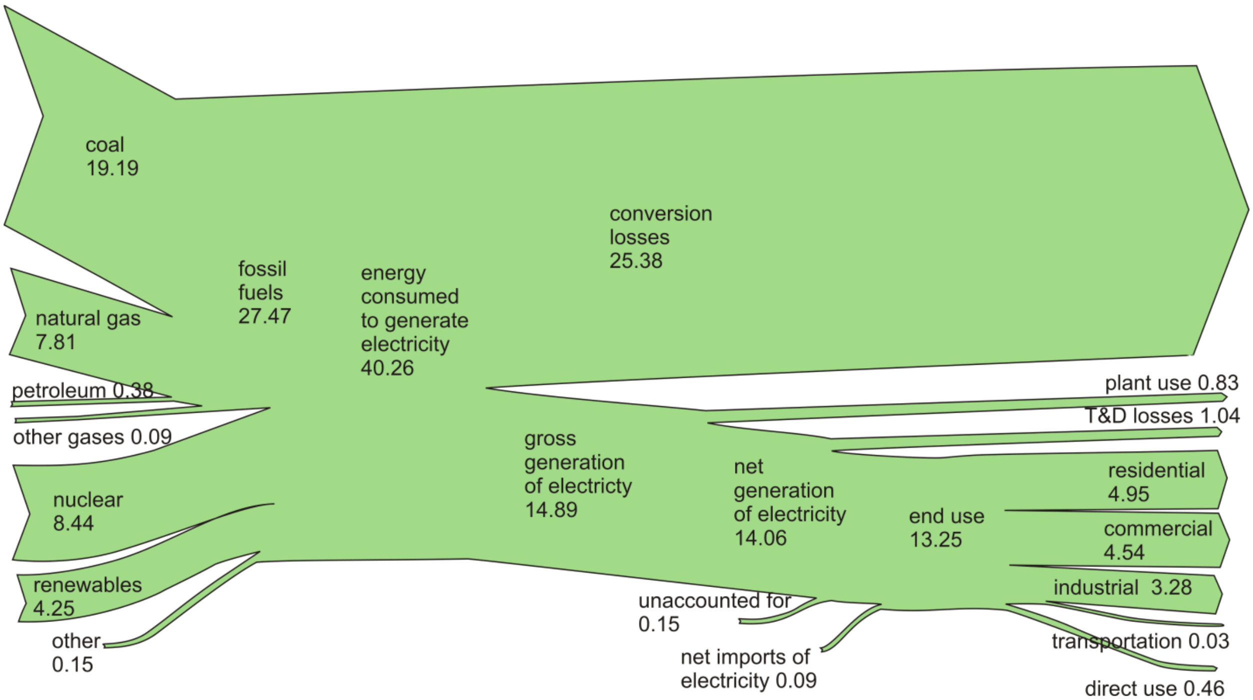



**Figure A.60**. Electricity Flow Diagram for 2010 (Quadrillion Btu)[407]

## A.15.2 Description of Metric and Measurable Elements

*(Metric 15) The energy efficiency of electric power generation and delivery (T&D).*

For generation, energy efficiency is subdivided into coal, petroleum, and natural gas; non-fossil sources are not considered in this metric. The combination of coal, petroleum, and natural gas makes up about 68-70 percent of the nation's electric power generation base. Because losses for T&D are so low in comparison and the data lacks detail, they are grouped together.

## A.15.3 Deployment Trends and Projections

Figure A.61, drawn using data from the EIA,[408] shows the trend in energy generation for electricity since 1990. The total amount of electricity consumed has increased during the last two decades, though not as quickly as in earlier decades. The graph shows that the majority of the energy still comes from fossil fuels, and that natural gas has experienced significant growth as a generation source in recent years while nuclear has remained static and coal has declined. From this we may conclude that improving efficiency will be of continuing importance.

[407] EIA 2011.
[408] EIA – U.S. Energy Information Administration. 2012a. "Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 Through 2010." *United States Electricity Profile, 2010*. Accessed July 19, 2012 at http://www.eia.gov/electricity/state/unitedstates/ (last updated January 30, 2012).

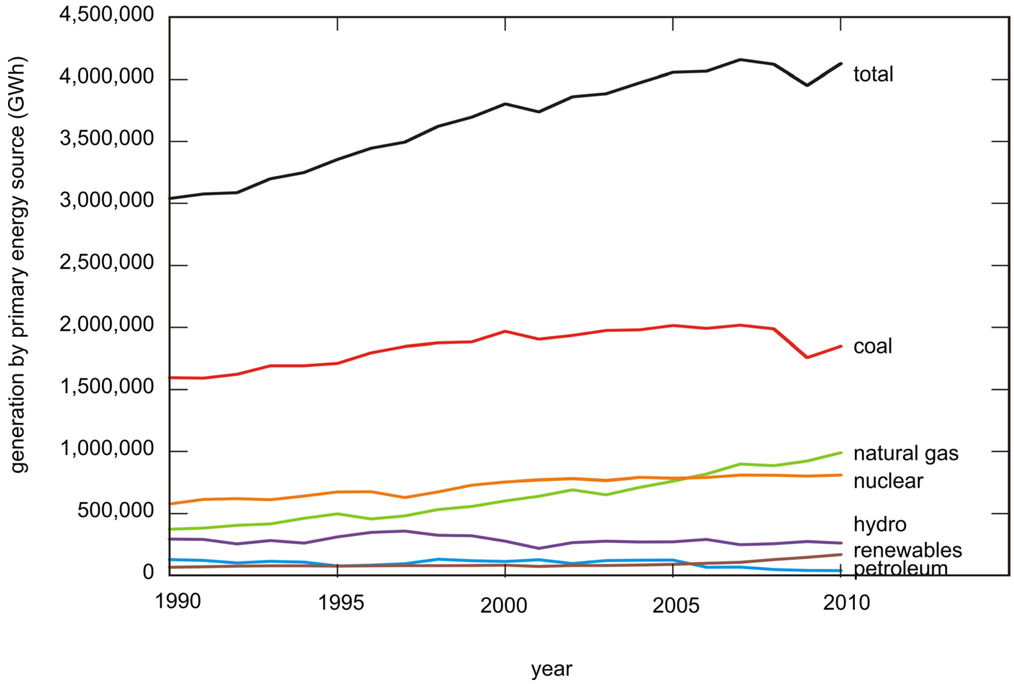



**Figure A.61**. Energy Consumption for Electricity Generation by Source

It may be observed that the total energy and the fossil-fuel component were decreasing in 2008 and 2009, but increased in 2010. Since nuclear and renewable energy did not show this change, we may conclude that there was an overall increase in electricity use, and it was met by fossil-fuel means. Although the annual energy review does not indicate so directly, it can be reasonably inferred that the increase was a restoration of some of the declines in energy consumption that resulted from the economic downturn. All sectors (residential, commercial and industrial) showed increased electric energy consumption during this time. The upturn should not be interpreted as a decrease in efficiency but rather an increase in economic activity.

Demand-side management programs and state-level electricity restructuring have increased competition among service providers, and this is expected to have promoted greater generation efficiency. Increases in the numbers of privately owned generation units and competitive wholesale electricity markets have prompted electricity providers to take steps to reduce operating costs and improve their operating performance. According to a recent study, smart grid technologies can help service providers increase overall system reliability, including transmission efficiencies, by as much as 40 percent.[409] In general, providers with lower generation costs are better able to maintain their market shares and maximize profits in wholesale electricity markets.

The efficiency of the actual generation process varies greatly depending on the electricity type, method of generation, and technology (including age) used for generation. According to the 2011 report from EIA, electricity produced from coal currently represents approximately 45 percent of all generation

[409] EPRI – Electric Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed May 30, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.

in the U.S., with efficiency levels of approximately 30 to 35 percent (see Figure A.62).[410] New "clean coal" technologies such as carbon capture and storage promise to enhance efficiency levels and are actively promoted by the U.S. Department of Energy (DOE) through the Clean Coal Technology Program and the Clean Coal Power Initiative.[411] However, efficiency data was not updated in the 2011 EIA report, so we have no data to examine the situation.

Electricity generation in the United States has seen relatively steady efficiency rates in the last 50 years, following the rapid growth in the efficiency of coal power in the 1950s. Single-cycle steam plants (coal and nuclear) produce the majority of electricity in the U.S. These plants, though not as efficient as some others, use relatively inexpensive fuels, are less capital-intensive than most renewable resources, and operate at much higher annual capacity factors[412] than renewables. The leveling off of the efficiency of coal-fired generation suggests the limitation of the Carnot efficiency for large plants.

The increase in gas-based efficiency seen in Figure A.62 shows the improvement in gas turbines, mostly due to greater use of combined-cycle power plants. The heat rate shown is the amount of fuel needed to produce a certain amount of electric energy. Thus, a lower heat rate means a higher production of power for a given amount of primary fuel. Overall generation efficiency has increased from 32.3% in 2007 to 37.0% in 2011 primarily due to the shift to natural gas combined cycle power plants from coal plants.[413]

---

[410] DOE – U.S. Department of Energy. 2011a. "Table 5.3. Average Operating Heat Rate for Selected Energy Sources, 2001 through 2010." *Electric Power Annual 2010*. Washington, D.C. Accessed July 17, 2012 at http://205.254.135.7/electricity/annual/pdf/table5.3.pdf (last updated November 2011).

[411] DOE -- U.S. Department of Energy. 2010. *Clean Coal Technology & The Clean Coal Power Initiative.* U.S. Department of Energy, Washington, D.C. Accessed October 21, 2013 at http://www.fossil.energy.gov/programs/powersystems/cleancoal/ (last updated July 9, 2013).

[412] The capacity factor gives the amount of energy produced compared to the amount that would be produced if the generator were working at 100% output all the time. For nuclear generators, the number is large; it has been about 90% for a decade in the U.S.; see "U.S. Nuclear Industry Capacity Factors 1971 – 2011" from the Nuclear Energy Institute: http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Generating-Statistics (retrieved 2012-05-30). For wind generation, it may be as low as 20% and is rarely above 40% because the wind is not consistent. Most fossil fuel plants are in-between, as they are turned on and off to follow the load on the power system.

[413] EIA—Energy Information Administration. September 2012g. Table 2.1f: Electric Power Sector Energy Consumption, 1949-2011, Table 8.2a: Electricity Net Generation: Total (All Sectors), 1949-2011 and Table 8.3b: Useful Thermal Output at Combined-Heat-and-Power Plants Electric Power Sector, 1989-2011. In Annual Energy Review 2011. DOE/EIA-0384(2011), U.S. Department of Energy, Washington, D.C. Accessed October 17, 2013, at http://www.eia.gov/totalenergy/data/annual/archive/038411.pdf (last updated September 2012).

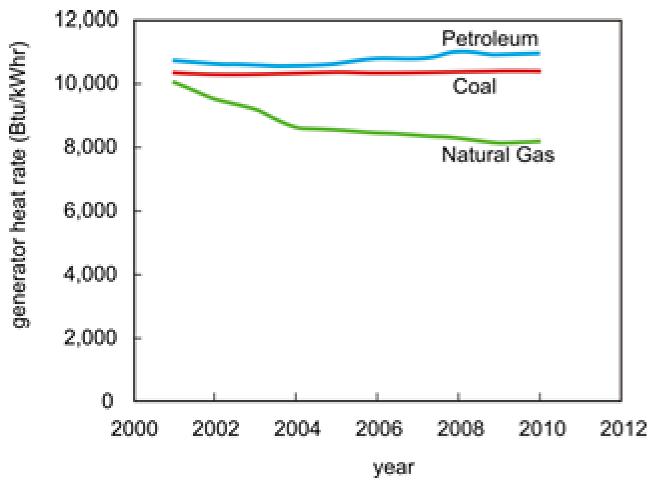



**Figure A.62**. Generation Heat Rates for Various Fossil Fuel Sources over Time

Not only have machines using gas become more efficient, the availability of natural gas has increased significantly since 2006. Figure A.63, adapted from EIA data provided by Deloitte Development, shows that natural gas wellhead prices have fallen from $7.97 per thousand cubic feet (Tcf) in 2008 to $3.95/Tcf in 2011.[414] Production increased from 25.6 to 28.6 million cubic feet during the same time period.[415] Note that these trends are generally attributed to the somewhat controversial practice of “fracking.” Due to the trends shown in Figure A.63, the result has been an improvement in generation efficiency and a reduction in the production of certain greenhouse gases.

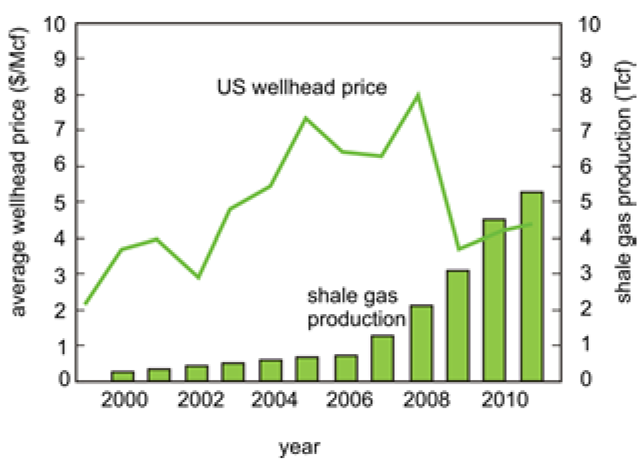



**Figure A.63**. Gas Price and Production Over Time[416]

Figure A.64, adapted from an EIA report,[417] shows a relatively high efficiency of transmission and distribution, with an almost steady level of efficiency over the past two decades. T&D efficiency grew to

[414] EIA – U.S. Energy Information Administration. 2012b. “U.S. Natural Gas Wellhead Price.” *Natural Gas*. Accessed August 2, 2012 at http://www.eia.gov/dnav/ng/hist/n9190us3a.htm (last updated July 31, 2012).
[415] EIA – U.S. Energy Information Administration. 2012c. “U.S. Natural Gas Gross Withdrawals.” *Natural Gas*. Accessed August 2, 2012 at http://www.eia.gov/dnav/ng/hist/n9010us2a.htm (last updated July 31, 2012).
[416] Ihne R and CK Ebinger. 2012. “Oil and Gas Sector. Liquid Markets: Assessing the Case for U.S. Exports of LNG.” Prepared by Deloitte Consulting LLP and The Brookings Institution. Accessed August 2, 2012 at http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_D2OilGas_Confn_May2012.pdf.

94.1 percent in 2008 from 92.3 percent in 1995. If the numbers are taken at face value, they represent significant gains in T&D efficiency since data were first collected. Even so, the energy loss is 260,000 GWh, approximately the amount produced by 30 large power stations operating continuously. Work on improving the efficiency level is clearly still justified, including the collection of better data.

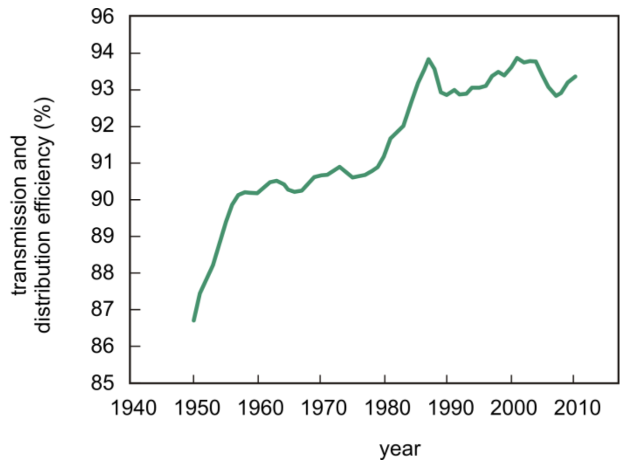



**Figure A.64**. Combined Transmission and Distribution Efficiency over Time

The problem with the energy loss numbers discussed above is that losses cannot be measured directly. Some values represent the small difference between two large numbers, meaning that a minor error in either number potentially has a large effect on the calculated efficiency.

The measurement of the energy generated is commonly performed with small uncertainty because the cost involved in the process is so large. Transmission losses can be calculated because the system configuration can be modeled and the parameters are known with good accuracy. Transmission losses are generally accepted to be about 4±1 percent. The energy that is consumed is routinely measured by the meters that are used for billing the customer. The energy losses cannot be modeled because the location of the load on a distribution feeder at any given time is not known.

Distribution system losses are commonly thought to be between 8 and 16 percent. It remains to be seen whether the better accuracy of the new advanced metering infrastructure (AMI) compared to the older electromechanical meters gives rise to a change in the apparent efficiency of delivery. Because the communication bandwidth of AMI systems is very low, even the new smart meters will not allow modeling and calculation of losses in real time. However, advancement in technologies such as AMI, data sharing and collection systems can help service providers collect and analyze data over longer time periods in an effort to better detect and monitor system losses.

DOE identified six primary analysis areas for recipients of smart grid investment grants which were allocated through funds from the *American Recovery and Reinvestment Act of 2009*. Energy efficiency in distribution systems is one of the six areas, with the objective of better understanding distribution

[417] EIA – U.S. Energy Information Administration. 2012d. "Table 10. Supply and Disposition of Electricity, 1990 Through 2010 (Million Kilowatthours)." *United States Electricity Profile, 2010*. Accessed July 19, 2012 at http://www.eia.gov/electricity/state/unitedstates/ (last updated January 30, 2012).

efficiency issues through study of smart grid deployment projects. Primary analytical focus of programs in this area is on voltage optimization, conservation voltage reduction and line losses.[418]

#### A.15.3.1 Associated Stakeholders

Associated stakeholders include:

- generation operators – Higher generation efficiency and reduced losses should mean greater profits for service providers. Generation operators may also be constrained by emissions requirements. Hence, using more efficient generators that discharge fewer emissions will be of interest.
- regional transmission operators – Power line losses can lead to congestion on a transmission path. Sometimes the situation requires grid operators to change generation schedules in some areas to protect the integrity of the grid as a whole. These "transmission loading relief" actions (TLRs) tend to peak in the summer months, and are logged by the North American Electric Reliability Corporation at a rate of a few hundred per month (300/month in July 2010). Hence, regional transmission organization (RTO) s would benefit from higher transmission efficiency.
- local, state, and federal energy policy makers (regulators) – Greater efficiency would mean reduced dependence on foreign fuel supplies, be they oil or natural gas or even coal, which pays obvious dividends from a security standpoint.
- end-users (consumers) – Transmission constraints cost consumers billions of dollars in congestion charges passed down from the utilities.
- policy advocates (environmental groups) – From an environmental perspective, greater generation efficiency leads to lower fuel usage and fewer emissions.

#### A.15.3.2 Regional Influences

Regional influences emerge due to the large differences in energy resources in various parts of the country. While fossil-fuel power plants are the largest producers of electricity in the U.S., in some parts of the nation, nuclear or hydroelectric power play important roles.

The average generation efficiency is different among the states. This difference is attributed to the average heat value of the coal, petroleum, and natural gas used in the states. For example, in 2008, the average heat value of coal used in Texas was 7,759 Btu per pound, while in California it was 11,667 Btu per pound.

[418] DOE – U.S. Department of Energy. 2012a. *Energy Efficiency in Distribution Systems: A DOE Analysis Approach*. Office of Electricity Delivery & Energy Reliability, Washington, D.C. Accessed August 2, 2012 at http://www.smartgrid.gov/sites/default/files/doc/files/Analysis%20Approach%20-%20Energy%20Efficiency%20in%20Distribution%20Systems%202012-03-01.pdf (undated webpage).

## A.15.4 Challenges to Deployment

### A.15.4.1 Technical Challenges

Perhaps it is fair to say that the "easy" improvements to efficiency have already been made. New initiatives in generation efficiency include improving the heat rate/emission rate/efficiency using carbon capture and sequestration. The work is proving costly and challenging.[419]

Reducing transmission losses would require adding high-voltage power lines (which is a strategy that usually runs into public opposition), finding better low-loss conductors and finding smarter, more efficient ways of moving power in congested, high-loss transmission corridors. These seem impractical and, at 4 percent transmission losses, may be beyond further improvement.

Distribution system losses, while not easy to calculate and very difficult to measure, can often be reduced by increasing the voltage of the distribution system. There are many voltages in use today in the U.S.,[420] and choosing a higher level would be feasible due to the availability of required infrastructure (e.g., fuses, transformers, insulators). However, it may mean reconductoring some lines or cables and installing new poles and insulators, and it will mean changing out the transformers. Nevertheless, it is a practical strategy that should be considered as growing load currents approach the limit of the distribution system. Utilities are beginning to mitigate some of these issues with systems such as volt-ampere-reactive (VAr) control and voltage reduction technologies. For example, Con Edison of New York is installing a voltage monitoring system that includes VAr and screening technologies connected to a supervisory control and data acquisition network that will remotely maintain unit station 4-kV bus voltage at a desired level determined by specific load voltage schedules.[421]

### A.15.4.2 Business and Financial Challenges

Electricity service providers, as protected monopolies for many decades, have developed cultures with low risk tolerance. They may not be well equipped to deal with the needs of an evolving marketplace. There are challenges in several areas:

- While there are technologies that could contribute to infrastructure improvements, such as superconducting cables and energy-storage systems, these options are costly, and may be economical only for niche problems.
- Significant improvements in energy efficiency will require active involvement by the electricity service provider.
- Utilities or aggregators may use demand response as a way to reduce peak loads. Improving price transparency and customer participation will be vital in managing the electric power system efficiently in the future. Such transparency and participation will involve new information and communication infrastructure.

[419] DOE – U.S. Department of Energy. 2011b. *Recovery Act: Implementation of the American Recovery and Reinvestment Act of 2009*. Washington, D.C .

[420] The following are considered standards: 1.2, 5, 15, 18, 25, 34.5, and 46 kV. Other values are also in use.

[421] DOE – U.S. Department of Energy. 2012b. "Consolidated Edison Company of New York, Inc. Smart Grid Deployment Project." In *Smartgrid.gov. Recovery Act Smart Grid Programs*. Accessed August 2, 2012 at http://www.smartgrid.gov/project/consolidated_edison_company_new_york_inc_smart_grid_deployment_project (undated webpage).

- While many of the largest power delivery assets have been operating without significant change for decades, investments in new technologies may provide new opportunities for efficiency gains. However, the business case must be made convincing to the state regulators that control rates.

### A.15.5 Metric Recommendations

Distribution systems are generally operated radially, with lines and cables leaving distribution substations at what is known as medium voltage (MV), a value typically around 12 kV. Losses on this system will be reduced by increasing the MV level of the distribution system. That would mean changing insulators, improving corona reduction devices (or perhaps adding some if they are not installed) and changing the low-voltage transformers. The fact that the system is radial implies that the change can be made one feeder at a time, so as to minimize the capital requirement impact. A future metric could be used to track such changes.

## A.16 Metric #16: Dynamic Line Ratings

### A.16.1 Introduction and Background

Dynamic line ratings (DLR), also referred to as real-time transmission line ratings, are a well-proven tool for enhancing the capability and reliability of electrical transmission system components when such components are limited in carrying capacity by temperature-induced sag. Modern DLR systems can be installed at a fraction of the cost of other traditional transmission line enhancement approaches, such as building new circuits or reconductoring existing ones.

The Edison Electric Institute reports that on top of the $10.2 billion invested in transmission by its members in 2010, some $54 billion is predicted to be spent between 2012 and 2014 on transmission upgrades.[422] A portion of this amount will come via the *American Reinvestment and Recovery Act of 2009* (ARRA) in the form of Smart Grid Investment Grant (SGIG) funding. Around $308 million of all SGIGs are specifically intended for upgrades to the transmission system. While no SGIG funding was issued to projects directly related to dynamic line ratings (DLR),[423] around $4.3 million was allocated to support the two DLR projects funded through Smart Grid Demonstration Project Program.[424] Overall, this grid investment is relatively small when compared with the approximately $14 billion in total grid investment that is projected for 2012[425] or to the $298 billion that the Brattle Group has estimated is required to upgrade transmission capability to meet future demand.[426]

While there are a number of factors that can limit the power carrying capacity of a particular transmission component (such as voltage instability, transient stability, and "N-1" reliability requirements) one of the primary limiting factors for transmission lines is temperature. When a transmission line current increases, the conductor heats, begins to expand, and causes the power line to sag. Allowable distances between power lines and other obstacles are specified by the National Electric Safety Code (NESC).

The amount of sag in a span of transmission line depends primarily on the conductor's material characteristics and construction. While line sag can be calculated with reasonable engineering accuracy for newer lines, the amount of sag an older line will exhibit is less predictable. Transmission line owners typically use survey techniques to verify the sag condition of their lines.

A standard practice is to apply a fixed rating, which usually is established using a set of conservative assumptions (i.e., high ambient temperature, high solar radiation, and low wind speed), to a transmission

[422] EEI – Edison Electric Institute. March 2012. Transmission Projects: At A Glance. Washington, D.C. Accessed on June 21, 2012 at http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf .

[423] DOE – U.S. Department of Energy. November 2011. *Recovery Act Selections for Smart Grid Investment Grant Awards - By Category*. Accessed June 13 2012 at http://energy.gov/sites/prod/files/SGIG Awards by Category 2011 11 15.pdf .

[424] SmartGrid.gov. 2011. "Smart Grid Demonstration Program." In *Recovery Act Smart Grid Programs,* Database. Accessed June 20, 2012, at http://www.smartgrid.gov/recovery_act/overview/smart_grid_demonstration_program.

[425] EEI 2012.

[426] Chupka M, R Earle, P Fox-Penner, and R Hledik. November 2008. *Transforming America's Power Industry: The Investment Challenge 2010-2030*. Prepared by The Brattle Group for The Edison Foundation, Washington, D.C. Accessed June 10, 2012 at http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry_Exec_Summary.pdf (undated webpage).

line. In contrast, DLR utilizes actual weather and loading conditions instead of fixed, conservative assumptions. By feeding real-time data into a DLR system, the normal, emergency, and transient ratings of a line can be continuously updated, resulting in a less-conservative, higher-capacity rating of the line about 95 to 98 percent of the time, and increasing capacity by 10 to 15 percent.[427] In a particularly interesting twist, transmission of wind energy might become enhanced by DLR given the cooling effect of wind.[428] In a recent study conducted by San Diego Gas & Electric (SDG&E), they found that monitored transmission lines had 40 to 80 percent more capacity than lines using static measurements. The difference represents lost transmission capacity, and in this case lost renewable energy that had to be replaced by fossil fuel energy. Thus, DLR could improve not only the efficiency of transmission line use but also provide an environmental benefit by allowing more transmission of renewable energy when static line-rating approaches would have reduced wind output.[429]

Seppa[430] originally listed three approaches to DLR: tension monitoring, surface-temperature monitoring, and weather-based ratings. A fourth, but less common, method is to measure the sag angle of the conductors with inclinometers.[431] More recent field trials also reveal some success with more direct approaches to the measurement of line sag. Seppa stated that the opportunity faced in 1999, and still faced today, for the application of DLR, "…could expect to generate an approximately 10 percent increase in the real transmission capabilities—the equivalent of 10,000 GW-miles of construction—by equipping less than 10 percent of transmission lines with real-time thermal ratings systems."[432]

### A.16.2 Description of the Metric and Measurable Elements

*(Metric 16.a) Number of transmission lines in the U.S. to which dynamic line ratings are applied.*

*(Metric 16.b) Percentage miles of transmission circuits operated under dynamic line ratings (miles).*

*(Metric 16.c) Yearly average U.S. transmission transfer capacity expansion due to the use of dynamic, rather than fixed, transmission line ratings (MW-mile).*

### A.16.3 Deployment Trends and Projections

The strain on our transmission system is showing, particularly as market participants and regulators are placing new requirements on the infrastructure for which it was not originally designed, such as

---

427 Seppa TO. 2005. "FACTS and Real Time Thermal Rating-Synergistic Network Technologies." In *Proceedings of the 2005 Power Engineering Society General Meeting*, Vol. 3, pp. 2416-2418, June 12-16, 2005, San Francisco, California. IEEE Power Engineering Society, Piscataway, New Jersey. Accessed June 10, 2012 at http://ieeexplore.ieee.org/iel5/9893/32012/01489342.pdf (undated webpage).

428 Oreschnick P. November 2007. "Dynamic Rating Allows More Wind Generation." *Transmission & Distribution World*. Accessed June 12, 2012 at http://tdworld.com/substations/power_dynamic_rating_allows/ (last updated November 1, 2007).

429 E Source. September 2009. *Environmental Benefits of Interoperability: The Road to Maximizing Smart Grid's Environmental Benefit*. Prepared by E Source for GridWise® Architecture Council, Richland, Washington. Accessed June 10, 2012 at http://www.gridwiseac.org/pdfs/environmental_interoperability.pdf (undated webpage).

430 Seppa TO. 1997. "Real Time Rating Systems." Presented at the *EPRI Workshop on Real Time Monitoring and Rating of Transmission and Substation Circuits: A Technology Increasing Grid Asset Utilization*, February 26–28, 1997, San Diego, California.

431 Schneider K. 2008. Communication between Kevin Schneider (Pacific Northwest National Laboratory[PNNL]) and Mark Weimar (PNNL), RE: "Distribution Networks Among Utilities," November 4, 2008, Portland, Oregon.

432 Seppa TO. 1999. "Improving Asset Utilization of Transmission Lines by Real Time Rating." Presented at T&D Committee Meeting, IEEE/PES Summer Power Meeting, July 22, 1999, Edmonton, Alberta.

facilitating competitive regional markets. Many of these changes have come about in the last few decades while, according to DOE, 70 percent of transmission lines are over 25 years old and so were probably built without consideration for these recent developments.[433]

For the past three decades, the dominant trend of our nation's transmission infrastructure is perhaps best pointed out by Hirst, who showed that, while the U.S. transmission grid continues to grow, since 1982 the long-term growth of transmission capacity has not kept up with the growth of peak demand.[434] As shown in Table A.21, this trend has begun to slow and perhaps reverse in the past few years. This reversal stems from a number of sources; some are short-term, such as stimulus investment through ARRA and demand decreases due to economic weakness, and others are longer-term, such as large-scale private investment driven by pricing policy shifts and environmental regulation, as shown in Figure A.65.

**Table A.21**. Transmission Capacity Growth and Summer Peak Demand for Four Decades[435,436]

| | Average Annual Percent Change | | | |
|---|---|---|---|---|
| | 1982-1989 | 1990-1999 | 2000-2009 | 2010-2021 |
| Transmission (miles) | 1.66% | 0.61% | 0.78% | 0.9% |
| Summer Peak (GW) | 2.82% | 2.63% | 1.08% | 0.5% |
| Miles/GW Demand | −1.12% | −1.63% | −0.28% | −0.3% |

If the long-term trend of investment does not keep up with demand or is permanently altered, the huge investment that is necessary (shown in Figure A.65) highlights the need for DLR. DLR will provide an additional 10 to 15 percent transmission capacity 95 percent of the time, and fully 20 to 25 percent more transmission capacity 85 percent of the time.[437] This increased capacity of existing equipment typically delays the need to invest in additional transmission capacity in response to increased demand.

[433] T&DW – Transmission & Distribution World. November 2006. *Fitch: U.S. Electric Transmission System Shows Its Age*. From a Special Report, Fitch Ratings. Accessed June 21, 2012 at http://tdworld.com/news/fitch-electric-transmission-report/.

[434] Hirst E. June 2004. *U.S. Transmission Capacity: Present Status and Future Prospects*. Prepared for the Edison Electric Institute and the Office of Electrical Transmission and Distribution, U.S. Department of Energy, Washington, D.C. Accessed June 15, 2014 at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/transmission_capacity.pdf (undated webpage).

[435] NERC – North American Electric Reliability Corporation. January 2012. *Electricity Supply and Demand (ES&D): Frequently Requested Data 2011 Reports (with 2010 Actuals)*. Princeton, New Jersey. Accessed June 10, 2012 at http://www.nerc.com/page.php?cid=4|38|41 (Last updated January 2012).

[436] Hirst 2004, Table 3.

[437] Seppa 1997.

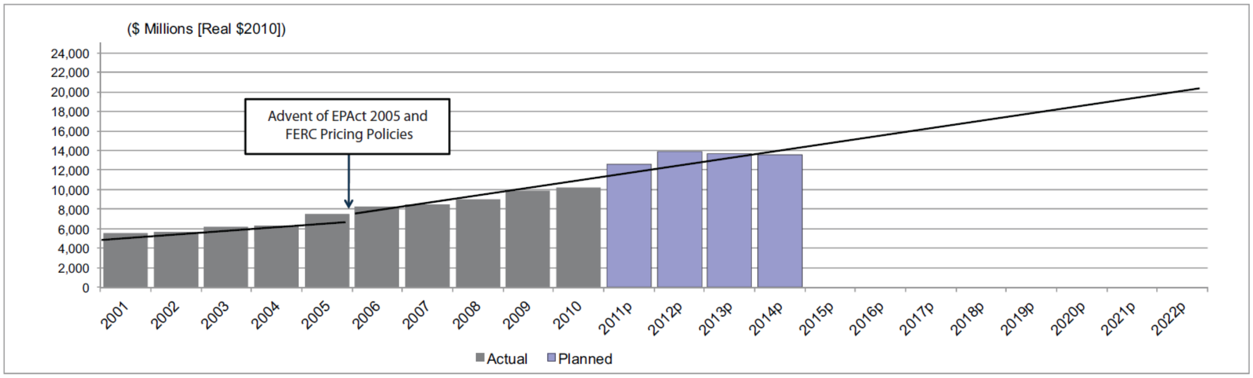



**Figure A.65**. Projected Annual Transmission Grid Investment[438]

Attempts to locate secondary sources with tabulations of the suggested measurements were unsuccessful. The number of locations where DLR is practiced appears to be small, monitoring only a fraction of the nation's transmission lines. The interviews of electricity service providers conducted for the 2010 Smart Grid System Report revealed that, on average, only 0.6 percent of respondents' transmission lines were dynamically rated when weighted by the number of customers served by each respondent. None of the electricity service providers interviewed for this report identified dynamically rated transmission lines within their networks (See Appendix B). In terms of ARRA investment, the SGDP provided $4.3 million in support of two dynamic line rating projects.[439]

Virginia Power installed the first CAT-1™ transmission monitoring system in 1991.[440] The Valley Group reports that at least 20 utilities in North America have CAT-1 dynamic line-monitoring equipment installed on their systems. However, only about half of all the utilities use the data in real time.[441]

The following is a sampling of products identified as being available, or nearly available, for installation in the nation's transmission system:

- ABB offers a wide-area monitoring system that provides thermal monitoring. The PSGuard Line Thermal Monitoring unit provides information on actual line temperature, trend in line temperature change by the second, present line resistance, line current, assessment of thermal limits, and assessment of transmission line loadability.[442]
- Schneider Electric's MiCOM P341 enables accounting for weather conditions in calculating line ratings.[443]

---

[438] EEI 2012.
[439] DOE – U.S. Department of Energy. 2012a. SmartGrid.gov, "Smart Grid Investment Grant Program" webpage. Accessed June 11, 2012 at http://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.
[440] CAT-1 is a trademark of The Valley Group, Inc., New York state.
[441] TVG – The Valley Group. 2010. *CAT-1 Transmission Line Monitoring System*. The Valley Group (a Nexans company), Markham, Ontario. Accessed June 20, 2012 at http://www.nexans.us/eservice/US-en_US/navigatepub_0_-17373_1673_40_4932/CAT_1_Transmission_Line_Monitoring_System.html (undated webpage).
[442] ABB – ABB Switzerland Ltd. 2005. *Line Thermal Monitoring—Dynamic Rating of Transmission Lines*. Baden, Switzerland. Accessed June 16, 2012 at http://library.abb.com/global/scot/scot221.nsf/veritydisplay/eace83bd6a60d884c12570d0002f99b4/$File/1002_LTM_PSGuard_Datasheet.pdf (undated webpage).
[443] Schneider Electric. Ca 2012. Interconnection Protection Relays – *MICOM P341 and P922G*. Accessed August 8, 2012 at http://www2.schneider-electric.com/sites/corporate/en/products-services/energy-distribution/products-offer/range-presentation.page?c_filepath=/templatedata/Offer_Presentation/3_Range_Datasheet/data/en/shared/energy_distribution/micom_p341_and_micom_p922g.xml.

- The Valley Group, Inc.'s, CAT-1 system and related products comprise a cable-tension type system launched in 1991[444] and tested at locations including SDG&E, Tennessee Valley Authority, and Kansas City Power and Light.[445,446,447]
- Pike Energy Solutions' ThermalRate™ system is a weather-based system by SaskPower.[448]
- The Electric Power Research Institute's Quasi-Dynamic Rating approach is a weather-based approach.[449]
- Ultrasonic sag sensors use sound waves to measure deflection.[450]
- Electric-field monitoring detects the displacement of the field source (in this case a transmission line).[451]

The current state-of-the-art technology is a "complete end-to-end solution" that provides all the elements necessary for real-time line ratings, including all necessary line sensors and full energy management system (EMS)/SCADA integration. Such a system can currently be installed on a 20 mile run in four or five days.[452]

Some of the above technologies are still in their infancy. The following are a few demonstration or pilot projects intended to determine the feasibility and reliability of implementing these relatively untested types of DLR equipment operating in real time:

- The Oncor Electric Delivery Company's Smart Grid Demonstration Project in the ERCOT area. The project, using 45 load-cell tension-monitoring units and eight master locations, will demonstrate that DLR can relieve congestion and transmission constraints, provide operational knowledge, ensure safety-code clearances are maintained, ensure that multiple monitoring units can be integrated, and quantify/identify any operational limits. Current constraints include understanding whether DLR technology is reliable, making sure electricity service provider planners understand the cost and benefit structure, and understanding the interoperability of the system with electricity service provider transmission management studies. The study area is in a critical congestion area near Dallas and is expected to be complete in 2013.[453] A preliminary report, issued in February 2012, found that the

---

444 TVG 2010.

445 Torre W. 1999. *Strategic Energy Research: Dynamic Circuit Thermal Line Rating*. P600-00-36, prepared for California Energy Commission. Accessed June 20, 2012 at http://www.energy.ca.gov/reports/2002-01-10_600-00-036.PDF (undated webpage).

446 TVG – The Valley Group. ca 2008. *Increasing Reliability While Decreasing Operating Costs: Real Time Ratings Provides Real Time Benefits to CAT-1 System Users*. Accessed on June 20, 2012 at https://www.nexans.com/US/2008/CostJustification-TVA.pdf.

447 TVG – The Valley Group. October 2003. *Increasing Reliability While Decreasing Operating Costs: Real Time Ratings Provides Real Time Benefits to CAT-1 System Users*. Accessed on June 20, 2012 at https://www.nexans.com/US/2008/Kansas%20City%20Power%20&%20Light.pdf.

448 Thomson N and D Lawry. June 1, 2008. "Getting Equipped: SaskPower Uses Dynamic Rating to Increase Line Capacity." *Utility Automation & Engineering T&D*. Accessed June 10, 2012 at http://www.elp.com/index/display/article-display/331131/articles/utility-automation-engineering-td/volume-13/issue-6/features/getting-equipped-saskpower-uses-dynamic-rating-to-increase-line-capacity.html (undated webpage).

449 Hydro Tasmania Consulting. July 2009. *Dynamic Transmission Line Rating – Technology Review*. 208478-CR-001.

450 NERC – North American Electric Reliability Corporation. December 2010. *Reliability Considerations from the Integration of Smart Grid*. Accessed on June 20, 2012 at http://www.nerc.com/files/SGTF_Report_Final_posted_v1.1.pdf.

451 NERC 2010.

452 NERC 2010.

453 Johnson J. June 2010. *Smart Grid Demonstration Project – Dynamic Line Rating (DLR) – Oncor Electric Delivery*. Presented at the ERCOT Reliability Operations Subcommittee Meeting,. Accessed June 10, 2012 at http://www.ercot.com/content/meetings/ros/keydocs/2010/0625/05._OncorDynamicLineRatingProject06252010_.ppt

region being examined has had few congestion events since the DLR sensors were installed. Only one of the eight lines monitored experienced congestion. The study has also indicated that N-1 scenario planning tends to dominate line loading, so for the higher voltage (345 kV) lines congestion is less of an issue, and DLR should perhaps be focused on medium voltage transmission lines (138 and 96 kV).[454]

- The New York Power Authority is conducting a demonstration project that evaluates instrumentation and dynamic thermal ratings for overhead transmission lines. The Electric Power Research Institute is providing their Dynamic Thermal Circuit Rating (DTCR) software, which provides dynamic ratings based on actual load and weather conditions. The real-time data will be provided using temperature monitors, video Sagometers,[455] and tension monitoring equipment applied to three 230 kV transmission lines. The project will be complete at the end of 2012.[456]
- The Valley Group (TVG) reported on a number of demonstration projects: Kansas City Power and Light (KCP&L) congestion relief, American Electric Power (AEP) West Wind Farm Integration, and Manitoba Hydro—Avoiding Curtailment. TVG reported no curtailment of firm or non-firm contracts after the installation of real-time ratings in the KCP&L congestion relief project. In the AEP West Wind Farm Integration project, 10 to 15 percent delivery of wind power was attained. DLR equipment was estimated to have deferred a $20 million line upgrade. The Manitoba Hydro—Avoiding Curtailment project reported real-time ratings above the static rating 99.9 percent of the time, and 30 percent above the static rating 90 percent of the time. The project demonstrated that DLR, as opposed to static line rating, avoided curtailment of hydroelectricity production and redispatch, which could have threatened reliability. The project also provided the electricity service provider a greater return on investment while planned upgrades remained on schedule.[457] TVG's CAT-1 Transmission Line monitoring system has also been used by the Tennessee Valley Authority to defer $25 million in system upgrades and prevent costly outages.[458] In a similar case study, KCP&L estimated a three-year payback of the installed cost of the system.[459]

#### A.16.3.1 Stakeholder Influences

Numerous stakeholders can be impacted by the successful deployment of DLR technologies, but the three primary stakeholders include:

- products and services suppliers, including information technology and communications – Producers of generation, control, and communications equipment that enable DLR systems are significant stakeholders.

[454] Oncor – Oncor Electric Delivery Company. 2011. *Oncor Electric Delivery Smart Grid Program: Technical Performance Report Fall 2011*. Oncor Electric Delivery Company, Dallas, Texas. Accessed June 14, 2012 at http://www.smartgrid.gov/sites/default/files/Oncor%20SGDP%20DE-OE0000320%20interim%20TPR1_02-16-2012.pdf.
[455] Sagometer is a trademark of the Electric Power Research Institute, Inc., Palo Alto, California.
[456] Mayadas-Dering J, L Hopkins, and A Schuff. 2009. *NY Utility Examines Integrating Dynamic Line Ratings*. Accessed June 10, 2012 at http://www.elp.com/articles/powergrid_international/print/volume-14/issue-7/features/ny-utility-examines-integrating-dynamic-line-ratings.html. (undated webpage).
[457] Aivaliotis SK. June 2010. *Dynamic Line Ratings for Optimal and Reliable Power Flow*. Presented at the 2010 FERC Technical Conference, June 24, 2010. Accessed June 10, 2012 at http://www.ferc.gov/EventCalendar/Files/20100623162026-Aivaliotis,%20The%20Valley%20Group%206-24-10.pdf (undated webpage).
[458] TVG 2008.
[459] TVG 2003.

- transmission providers – Depending on the size and location, the insertion of DLR technologies into existing power transmission assets could enhance asset capacity and defer expensive new infrastructure investments (i.e., new transmission lines).
- end users (customers) – Successful deployment of DLR technologies will result in a power grid that has higher capacity and is more reliable. In addition, increases in electricity customers' costs can be avoided through the avoidance of costs associated with installing new transmission lines.

#### A.16.3.2 Regional Influences

IOUs and transmission-only companies (TRANSCOs) have taken the lead in making investments in expanding the capacity of existing infrastructure and attempting to site and construct new infrastructure.[460] The actions of state and local regulators will continue to have a profound influence on investment decisions of whether to purchase transmission infrastructure.

No region is immune to the persistent trend in which transmission growth has been outpaced by demand growth (see Hirst[461] for details concerning this trend in each U.S. region). One can observe, however, that some regions (such as the Western Electricity Coordinating Council [WECC] and Mid-Atlantic Power Pathway [MAPP]) maintain their ratios of transfer capacity to peak demand up to four times higher than others. This pattern could result from limitations driven by longer transmission distances and more separated population centers in these regions as compared with other U.S. locations, rather than thermal considerations. This highlights that care must be taken when investing in DLR to ensure that temperature is the dominant limiting factor for line capacity in the region of prospective investment.

### A.16.4 Challenges

There are several identified barriers that may prevent or significantly reduce growth in the application of DLR to existing transmission lines in the United States. As is similar in other industries, the economic barriers are more significant than the technical challenges in stimulating deployment. Technical barriers include factors which limit transmission line capacity, lack of necessary sensor and data transmission capacity, lack of EMS ability to make use of available real-time data, and the need to train personnel to read DLR information correctly. The most significant business challenge is providing the appropriate market incentives to the right entities to recover investment in DLR equipment.

#### A.16.4.1 Technical Challenges

The goal of DLR is to enable higher capacity utilization of existing transmission lines. Unfortunately, other limiting factors such as voltage instability, transient stability, and N-1 reliability requirements can also significantly affect transmission-line transfer capacity more than the thermal limitations being monitored by DLR. The Oncor DLR study supported this position, showing where the carrying capacity of the higher voltage transmission lines was never reached due to the requirement to have backup capacity for such lines, typically halving the amount of electricity that might otherwise have to be carried.[462]

---

[460] T&DW 2006.
[461] Hirst 2004.
[462] Oncor 2011.

Besides the equipment associated with measurements for calculating DLR, the measurement information must be communicated to system control centers. In many cases the required line monitoring equipment is installed but the data is not made use of in real time by the utilities' EMSs.[463] The state estimation and analysis applications run in the control center must have the features that take DLR information and continually refresh the alert and alarm mechanisms within the applications so that the operator is notified of potential violations and harmful situations. In addition, typical control center seasonal applications must be augmented to accept DLR measurements even though they already deal with seasonal changes in line ratings.

In addition, Mayadas-Dering et al. (2009) list several technical challenges to the acceptance of DLR. These challenges include educating asset-management and operations personnel in the technical aspects of DLR to gain better acceptance of the accuracy of the dynamic ratings, DLR rating variability, availability and reliability of communications links to SCADA from remote substations, and instrumentation reliability due to the vulnerability of overhead lines to extreme weather conditions.[464]

As with other smart grid technologies that transmit data, a key technical challenge is maintaining the security of that data. Ensuring that the data is not intercepted or manipulated (with the latter action having very high potential for harm) will be paramount as DLR systems are rolled out across the entire grid.[465]

#### A.16.4.2 Business and Financial Challenges

Because the grid traverses multiple regions, industries, and functions, it is challenging to obtain the necessary information on the state of the grid and to know who is responsible for coordinating and sharing responsibility for making enhancements. This leads to challenges to create incentives for investing in additional capacity.

Seppa (2004) notes a significant business barrier to acceptance of DLR: net societal benefits that do not necessarily accrue to the investor. Dynamic ratings technology benefits the whole system, but the investor does not necessarily obtain benefits in accordance with their costs.[466]

### A.16.5 Metric Recommendations

Inadequate data were available to quantitatively assess the suggested measurements in this metric. A small number of sites exist where DLR is practiced. However, a more comprehensive interview approach with representative service providers will be needed to quantitatively identify, track, and measure the advantages achieved at those sites. Future inclusion of DLR data as a part of the Energy Information Administration Form EIA-411, Coordinated Bulk Power Supply Program Report, will immediately improve our understanding of the current status of the technology, and will allow for the development of trends and predictions as the data is collected consistently over time.

[463] TVG 2010.
[464] Mayadas-Dering et al. 2009.
[465] NERC 2010.
[466] Seppa TO. 2004. *Increasing Transmission Capability by Dynamic Rating of Lines and Transformers – A Low Risk/High Payback Strategy*. The Valley Group, Ridgefield, Connecticut. Accessed June 10, 2012 at http://docs.cpuc.ca.gov/published/RULINGS/44759/44759Att5.ppt (undated webpage).

Metric 16.c should be updated to reflect how increased capacity due to DLR installation is actually being utilized. As discussed in section A.16.3, the preliminary report of the Oncor DLR demonstration project indicated that often there are factors that limit line capacity other than the static rating (in the case of Oncor, the large lines were limited by N-1 reliability requirements). There is little point to installing DLR on lines that never approach the static capacity; the metric should be reshaped to reflect this, and so drive the most efficient use of this technology.

# A.17 Metric #17: Customer Complaints Regarding Power Quality Issues

## A.17.1 Introduction and Background

Power Quality (PQ) is a simple but subjective term that describes a large number of issues found in any electrical power system. The definition of a PQ incident varies widely, depending on the customer being served. Customers are affected by PQ incidents differently according to their needs. Residential customers tend to be affected more by sustained interruptions, whereas commercial and industrial customers are troubled mostly by voltage sags and momentary interruptions. A voltage sag, as defined by the IEEE Standard 1159-1995, is a decrease in root-mean-square voltage at the power frequency for durations from 0.5 cycles to 1 minute, reported as the remaining voltage.[467] Momentary interruptions are usually just a few seconds, but can last up to a minute, whereas sustained interruptions are usually between 1 and 5 minutes.

The smart grid system has the ability to offer several pricing levels for varying grades of PQ, which is expected to give customers more choices. Currently, the standard goal for utilities in relation to power interruptions is 3 to 4 "nines." Three nines represent 99.9 percent reliability and correspond to an outage time of 8.76 hours per year while four nines (99.99 percent) is equivalent to approximately 1 hour of downtime per year. Premium power of six to nine nines (99.9999 to 99.9999999 percent) would allow only 31 seconds to 0.03 seconds of interruption per year, respectively.

Smart grid technology can utilize advanced controls to allow for rapid diagnosis and solutions to PQ events, as well as to decrease the number of PQ disturbances from weather events, switching surges, line faults, and harmonic sources. Potential energy storage capabilities of smart grid systems can further benefit PQ, resulting in fewer interruptions or outages.[468] A principal characteristic of smart grid development includes enhanced PQ to avoid production and productivity losses through digital devices.[469]

Customer complaints regarding smart grid deployment tend to revolve around advanced metering infrastructure (AMI), particularly inaccuracies in smart meter readings. A recent study conducted by the EIA identified electricity bill errors and meter inaccuracies as primary customer complaint categories.[470] In total, 23 projects were analyzed in detailed case studies, with 13 representing successful demonstration projects and 10 representing projects with significant delays or complete cancellation. Of the 10 projects that were significantly delayed or cancelled, each one cited consumer issues as either a primary or

[467] IEEE – Institute of Electrical and Electronics Engineers. 1995. *IEEE Recommended Practice for Monitoring Electric Power Quality*. IEEE Std 1159-1995, Piscataway, New Jersey. Accessed October 25, 2010 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=475495 (undated webpage).

[468] EPRI – Electric Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed May 30, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.

[469] NETL – National Energy Technology Laboratory. 2010. *Understanding the Benefits of the Smart Grid*. DOE/NETL-2010/1413, prepared for the U.S. Department of Energy, Washington, D.C. Accessed April 14, 2012 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/06.18.2010_Understanding%20Smart%20Grid%20Benefits.pdf (undated webpage).

[470] EIA – U.S. Energy Information Administration. 2011a. *Smart Grid Legislative and Regulatory Policies and Case Studies*. Independent Statistics & Analysis, Washington, D.C. Accessed May 30, 2012 at http://www.eia.gov/analysis/studies/electricity/pdf/smartggrid.pdf.

contributing factor to the project's failure.[471] Table A.22 illustrates all drivers for smart grid project cancellation or postponement.[472] The same study did not identify PQ issues as a significant source of customer complaints.

### A.17.2 Description of Metric and Measurable Elements

*(Metric 17) The percentage of total retail customer complaints to their service providers which are related to power quality issues (excluding outages).*

### A.17.3 Deployment Trends and Projections

In the past, PQ incidents have been rather hard to observe and diagnose because of their short interruption period. The increase in power-sensitive and digital loads has forced us to more narrowly define PQ. For example, 10 years ago a voltage sag might be classified as a drop of 40 percent or more for 60 cycles, but now it may be a drop of 15 percent for five cycles.[473] The EIA collects data on major disturbances and unusual occurrences in the electric system. In 2011, at least 26.2 million electricity customers experienced a major disturbance or electricity outage.[474] However, EIA does not collect data on PQ and consumer complaints.

A loss of power or a fluctuation in power causes commercial and industrial users to lose valuable time and money each year. Cost estimates of power interruptions and outages vary. A 2002 study prepared by Primen concluded that power quality disturbances alone cost the U.S. economy between $15 and $24 billion annually.[475] In 2001, the EPRI estimated power interruption and power quality cost at $119 billion per year,[476] and a more recent 2004 study from Lawrence Berkeley National Laboratory estimated the cost at $80 billion per year.[477] A 2009 National Energy Technology Laboratory (NETL) study suggests that these costs are approximately $100 billion per year,[478] and further projected that the share of load from sensitive electronics (chips and automated manufacturing) will increase by 50 percent in the near future.[479]

---

[471] EIA 2011a.

[472] EIA 2011a.

[473] Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. ORNL/TM-2004/91, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed August 8, 2012 at http://www.innovations.harvard.edu/showdoc.html?id=651 (undated webpage).

[474] EIA – U.S. Energy Information Administration. 2011b. *Electricity: Electric Disturbance Events - Monthly and Annual Summaries*. Accessed May 14, 2012 at http://www.eia.gov/cneaf/electricity/page/disturb_events.html (undated webpage).

[475] McNulty S and B Howe. 2002. *Power Quality Problems and Renewable Energy Solutions*. Prepared for the Massachusetts Renewable Energy Trust by Primen, Madison, Wisconsin. Accessed July 13, 2012 at http://www.mtpc.org/Project%20Deliverables/PP_General_Power_Quality_Study.pdf.

[476] Lineweber D and S McNulty. 2001. *The Cost of Power Disturbance to Industrial & Digital Economy Companies.* Prepared by Primen for the Consortium for Electric Infrastructure to Support a Digital Society, Electric Power Research Institute, Palo Alto, California. Accessed October 18, 2008 at http://www.onpower.com/pdf/EPRICostOfPowerProblems.pdf (undated webpage).

[477] Hamachi LaCommare K and JH Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. LBNL-55718, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf (undated webpage).

[478] NETL – National Energy Technology Laboratory. 2009. *Smart Grid Principal Characteristics Provides Power Quality for the Digital Economy.* DOE/NETL-2010/1412. Accessed June 28, 2010 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/Provides%20Power%20Quality%20for%20the%20Digital%20Economy%20%28Oct%202009%29.pdf (undated webpage).

[479] NETL 2009.

**Table A.22.** Key Drivers for Smart Grid Pilot Program Cancellation or Postponement

| Project Name | Lack of Funding or Cost Issues | Customer Issues | | | | | Technological Issues | | State/Local Regulatory Orders Causing Delays | Observing Other Projects Before Proceeding |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Health Concerns | Privacy Concerns | Negative Response to Rate Increases | Inadequate Customer Education for Effective System Use | Customer Service Issues | Equipment or Construction Related Problems | Waiting for Technological Advances | | |
| BGE Smart Meter Pilot Program | 🟢 | | | 🔵 | 🟢 | | | 🔵 | 🔵 | |
| CL&P Plan-it Wise Energy Program | 🟢 | | 🔵 | 🔵 | | | | | 🔵 | |
| Consumers Energy SmartStreet Pilot and Full Scale Smart Meter | 🟢 | | | | | | | 🔵 | 🔵 | 🔵 |
| DP&L Customer Conservation and Energy Management Plan | 🔵 | | 🔵 | 🔵 | | | | 🟢 | | 🔵 |
| HECO Smart Meter Pilot Program | 🔵 | | | | | | 🟢 | | 🔵 | |
| LIPA BPL and Wireless Communications Demonstration | 🟢 | 🔵 | | | | | 🟢 | | | |
| PG&E SmartMeter Program | | 🟢 | 🔵 | | 🔵 | 🔵 | 🟢 | | 🔵 | |
| PSE PEM Program | 🔵 | 🔵 | | 🟢 | 🔵 | | | | 🔵 | |
| Snohomish County PUD Smart Grid Project | | | | 🔵 | | | | 🟢 | | |
| Xcel Energy SmartGridCity | 🟢 | | 🔵 | | 🔵 | | 🔵 | | 🔵 | |

Key driver for postponement/cancellation 🟢

Other driver for postponement/cancellation 🔵

According to a recent EPRI study, approximately 90 percent of power quality events, such as electricity interruptions, are caused by the electric distribution system.[480] Smart grid technology can improve distribution systems, thus enhancing overall reliability by as much as 40 percent.[481] The research team conducted interviews in support of this report with 30 public, municipal, and non-profit electricity service providers.

Public, municipal, and non-profit electricity service providers were surveyed (see Appendix B) to estimate PQ. The survey asked respondents to estimate the percentage of customer complaints related to PQ issues (excluding outages). The surveyed electricity service providers provided the following information regarding PQ-related customer complaints:

- 1.2 percent of residential customer complaints are related to power quality issues (excluding outages)
- 0.4 percent of commercial customer complaints are related to power quality issues (excluding outages)
- 0.1 percent of industrial customer complaints are related to power quality issues (excluding outages)

Recently, PQ has moved from customer-service problem solving to an integral part of the power-system performance process. The design of PQ devices for monitoring quality has not changed significantly in the past decade. Instead, the hardware, firmware, and software utilized by these systems have advanced dramatically. These changes are driven by market demands, standardization of measurement techniques and communication protocols, specialized large-scale integrated circuits, and improvements in software methodology. The latest PQ devices use web browsers to allow remote access to information.

The Smart Grid Consumer Collaborative (SGCC) conducts regular interviews and surveys with electricity consumers in an effort to ensure stakeholder perspectives are accurately represented as smart grid technologies continue to be deployed around the country. A recent respondent indicated that they thought a primary benefit of smart grid development is electric distribution system consistency and the ability to better monitor power surges, spikes and lags in an efficient manner.[482] Throughout the SGCC survey responses received by the research team, customers generally agreed that smart grid technologies had the potential to manage and improve PQ by integrating digital systems that could better monitor the electricity system.[483]

#### A.17.3.1 Associated Stakeholders

There are a number of stakeholders engaged in PQ issues:

- electric-service retailers working toward providing better PQ to customers
- end users (residential, commercial, and industrial users) needing consistent power quality
- regulators interested in enhancing PQ and better serving the customer base.

---

[480] EPRI 2011.
[481] EPRI 2011.
[482] Moody I. 2012. Email from Ivonne Moody (Smart Grid Consumer Collaborative) to Chrissi Antonopoulos (Pacific Northwest National Laboratory), Subject: "Data and Research Inquiry," dated June 15, 2012, Portland, Oregon.
[483] Moody 2012.

### A.17.3.2 Regional Influences

Regional PQ problems surface for several reasons, including climate, design of the distribution system, maintenance levels, the geographical features of an area, the number and types of customers (residential, commercial, or industrial), the economic health of a region, and the fact that utilities have different distribution systems. Therefore, interruption costs for comparable customers in different regions could vary significantly.

Also, PQ is dependent on the number and types of customers in a region. PQ-related interruption costs for a similar type of customer will differ depending on the region of the country, what industries predominate in the area, the local demographics, and the economic health of the region.

The Texas Electric Choice Education Program publishes electricity customer complaint records. According to recent data, a total of 2,249 retail electric customers filed official complaints with Texas utilities between December 2, 2011 and May 31, 2012.[484] Of this total, 808 pertained directly to quality of service, discontinued service, or provision of service, representing approximately 36 percent of all complaints.

## A.17.4 Challenges to Deployment

Measuring PQ presents a challenge because of the regional influences of a given area and the inconsistency in definitions and reporting of PQ. Different geographical issues, such as weather, terrain and demographics, create inconsistencies that make it difficult to compare PQ across regions. The PQ of electrical service is a bit more complex to measure than its reliability because PQ events are harder to observe and diagnose due to their short duration and the fact that definitions and standards are evolving.

### A.17.4.1 Technical Challenges

Residential, commercial, and industrial consumers will require different levels of PQ, but standards organizations have not created standards for categories of PQ from which consumers can choose according to their needs. Standards for various grades of delivered power could serve as the basis for differentiated PQ pricing. Also, more distinct definitions and better reporting and handling of evolving PQ issues would help clarify the topic, which is still not well understood. Improving PQ will require enhancing the quality of power across a grid, but consumers will also increase their resilience to PQ disruptions.[485]

As smart grid technologies continue to develop, including increased penetration of distributed energy resources such as renewable systems, PQ issues are more likely to arise. For example, large amounts of photovoltaic interconnection can cause flicker, harmonic disruptions and direct current injections—all of which negatively impact the distribution system.[486] Avoiding these types of PQ issues will be a focus of interconnection policy.

[484] Texas Electric Choice Education Program. 2012. *Customer Complaint Statistics*. Austin, TX.
[485] NETL 2009.
[486] Coddington M. 2012. *PV Interconnection, Standards & Codes, High Penetration Case Study*. Presented at the WAPA Workshop on February 23, 2012, prepared by the National Renewable Energy Laboratory, Golden, Colorado. Accessed June 4, 2012 at http://www.uwig.org/Golden2012/Hi-PenPV-Coddington.pdf.

NETL's 2009 PQ report identified specific challenges and technologies to improve PQ across the entire smart grid. These improvements include developing premium power programs (such as setting aside specific office parks and areas for premium power usage), developing storage devices (such as superconducting magnetic energy storage) to supply PQ-sensitive consumers ultraclean power, and deploying distributed generation devices capable of providing clean power to local sensitive loads.[487] Specifically, this requires technologies with the ability to identify and correct the failures that result in PQ issues, such as dynamic voltage restorers, static compensators, and thyristor-controlled static capacitors.[488]

#### A.17.4.2 Business and Financial Challenges

There are costs associated with implementing advanced PQ devices that some may not be willing to assume. PQ devices include those used by the utilities to monitor and diagnose problems, and devices used by the end-user that depend on the size and type of the critical load. Typically, end-user devices are categorized in three groups: individual operations (controls or individual equipment protection), sensitive sub-facilities (individual circuit protection), and the entire load (at the electric-service entrance). PQ-enhancing devices are still too expensive to be widely used. Distribution system upgrades, including PQ-specific equipment, have been estimated to cost between $309 and $403 billion over the next 20 years.[489] Such significant amounts could be barriers for further investment without rate recovery policies to offset up-front capital costs.

### A.17.5 Metric Recommendations

Customer sentiment regarding PQ issues is captured by measuring PQ complaints by customers as a percentage of total complaints. No data were found to meet the requirement of Metric 17 outside of the interviews conducted specifically for this report. To improve measurement, a research team could consider collaborating with research organizations, authorities and industry to establish a consistent data source.

What constitutes a PQ complaint is unfortunately open to interpretation, and it is advisable that such thresholds be established early so that progress can be quantified. Such thresholds or measurements for PQ could potentially be established by a collaborative effort between stakeholders identified in this report and relevant government agencies. Consideration should also be given to constructing a clear definition of what constitutes a PQ complaint. In developing this definition, any research team wishing to measure this metric should work closely with electric-service retailers and subject-matter experts. Further, the number of interviews should be expanded to generate a more precise assessment of this metric.

[487] NETL 2009.
[488] NETL 2009.
[489] EPRI 2011.

# A.18 Metric #18: Cybersecurity

## A.18.1 Introduction and Background

The interconnected North American grid has achieved and sustained an enviable record of reliability through the application of numerous technological and operational efficiencies and regulatory oversight. The grid's complexity and interconnected nature, however, pose unknown risks since under certain circumstances, problems occurring in one area may cascade out of control and affect large geographical areas.

The technology developments of the smart grid will make the power system more dependent on information systems and external communications networks. The interconnected nature of the communications systems that support regional and interregional grid control, and the need to continue supporting older legacy systems further compound these security challenges.[490] Additionally, with the advent of inexpensive microcontrollers, there is a growing trend for increased intelligence and capabilities in field equipment installed in substations, within the distribution network, and at the customer's premises. This increased control capability, while vastly increasing the flexibility and functionality to achieve better economies, also introduces new cyber-vulnerabilities that have not previously existed.

## A.18.2 Description of Metric and Measurable Elements

An understanding of component-level and associated system-level vulnerabilities will be necessary to quantify cybersecurity issues inherent in smart-grid deployments, particularly when these elements can be used to control or influence the behavior of the system. Assessments will be needed, both in controlled laboratory or test-bed environments and in actual deployed field conditions, to explore and understand the implications of various cyber-attack scenarios, the resilience of existing security measures, and the robustness of proposed countermeasures.

*(Metric 18) The electric power industry's compliance with the North American Electric Reliability Corporation Critical Infrastructure Protection (CIP) standards.* (See Table A.23 and Table A.24).

Designed to maintain the integrity of North America's interconnected electrical systems, the NERC CIP standards establish minimum requirements for cybersecurity programs protecting electric control and transmission functions. However, it should be noted that these standards do not apply to distribution systems which typically fall under the purview of the states. On January 17, 2008, the FERC directed NERC to further tighten the standards to provide for external oversight of classification of critical cyber assets and removal of language allowing variable implementation of the standards. Since then NERC CIP standards have gone through a series of revisions. The most current standard approved by the Board of Trustees is Version 4a.[491] Versions 3, 4 and 4a are in effect in various regulatory jurisdictions. Version 3 is the most current enforced version in the United States. As of July 2012, Version 5, Draft 2, of the

[490] NERC – North American Electric Reliability Corporation. 2009a. *Implementation Plan for Version 3 of the Cyber Security Standards CIP-002-3 through CIP-009-3*. Princeton, New Jersey. Accessed July 13, 2010 at http://www.nerc.com/docs/standards/sar/V3_Implementation_Plan_Redline_last_posting_2009Nov19.pdf (undated webpage).

[491] NERC – North American Electric Reliability Corporation. 2012a. *Reliability Standards*. Accessed May 29, 2012 http://www.nerc.com/page.php?cid=2|20 (undated webpage).

standards was voted on (May 21, 2012) and none of the balloted items was approved.[492] As of this writing, the drafting team is reviewing comments.[493]

**Table A.23**. Summary of the NERC Critical Infrastructure Protection Standards CIP-002 – CIP-009

| NERC Standard | Subject Area |
|---|---|
| CIP-002 | Critical Cyber Asset Identification |
| CIP-003 | Security Management Controls |
| CIP-004 | Personnel and Training |
| CIP-005 | Electronic Security Perimeter(s) |
| CIP-006 | Physical Security of Critical Cyber Assets |
| CIP-007 | Systems Security Management |
| CIP-008 | Incident Reporting and Response Planning |
| CIP-009 | Recovery Plans for Critical Cyber Assets |

**Table A.24**. Summary of the NERC Critical Infrastructure Protection Standards CIP-010 – CIP-011 (Emerging)

| NERC Standard | Subject Area |
|---|---|
| CIP-010 | BES Cyber System Categorization[(a)] |
| CIP-011 | BES Cyber System Protection<br>BES Cyber System Categorization |

(a) BES = bulk electricity system

CIP-002-4 has now become CIP-010-1, and CIP-003-4 through CIP-009-4 were consolidated into CIP-011-1.

In addition to NERC CIP, National Institute of Standards and Technology (NIST) has published three volumes of cybersecurity guidelines. The NIST guidance, which is a broad risk-management strategy, is applicable for all smart grid systems.[494]

### A.18.3 Deployment Trends and Projections

The implementation schedule for entities responsible for the reliability of the North American bulk electricity systems was established in the revised implementation plan for cybersecurity standards CIP-002-1 through CIP-009-1. During the schedule, these entities will undergo a process of identifying

[492] NERC – North American Electric Reliability Corporation. 2012b. . *Standards Announcement - Updated*. Washington, D.C.
[493] NERC – North American Electric Reliability Corporation. 2012c. *Project 2008-06: Cyber Security Order 706*. Accessed May 29, 2012 at http://www.nerc.com/pa/Stand/Pages/Project_2008-06_Cyber_Security.aspx (undated webpage).
[494] NIST – National Institute of Standards and Technology. 2010b. *Guidelines for Smart Grid Cyber Security: Vol. 1, Smart Grid Cyber Security Strategy, Architecture, and High-Level Requirements: Vol. 2: Privacy and the Smart Grid; Vol. 3, Supportive Analysis and References,* NISTIR 7628. Accessed November 9, 2012 at http://csrc.nist.gov/publications/PubsNISTIRs.html#NIST-IR-7628 (last updated May 13, 2014).

and protecting critical cyber assets that affect and/or control the reliability of the bulk electricity systems.[495]

The aforementioned implementation schedule established various deadlines for when responsible entities were required to become substantially compliant and auditably compliant with each standard. Responsible entities that were mandated to register during 2006 were required to become auditably compliant by December 31, 2010. Balancing authorities, transmission operators, and reliability coordinators, including those coming into compliance with NERC's Urgent Action Cyber Security Standard 1200 (UA 1200), were required to become auditably compliant by the end of the second quarter of 2010. A revised implementation plan details the schedule for transitioning from Version 1 to Version 3 of the NERC CIP standards and provides dates for implementation and compliance for U.S. nuclear power plant owners and operators.[496]

Violations of CIP-002 through CIP-009 have grown as a portion of all new violations. Figure A.66 illustrates this trend. Two observations are worth noting about this graph. First, the ramp up in accordance with the NERC CIP implementation plans makes more entities subject to the CIP regulations. Second, a preliminary screening process resulted in about 200 CIP violations submitted by the Western Electricity Coordinating Council (WECC) in May 2011. As more entities go through their implementation plan and mitigate violations, these numbers should begin to drop. During 2012, there were 1,113 CIP violations of CIP-002 through CIP-009, up from 1,059 violations in 2010.[497,498]

---

[495] NERC – North American Electric Reliability Corporation. 2009b. *(Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1*. Princeton, New Jersey. Accessed June 2012 at http://www.nerc.com/fileUploads/File/Standards/Revised_Implementation_Plan_CIP-002-009.pdf (undated webpage).

[496]NERC – North American Electric Reliability Corporation. 2010. *Revised Implementation Plan for Version 3 of Cyber Security Standards CIP-002-3 through CIP 009-3*. Princeton, New Jersey. Accessed May 29, 2010 at http://www.nerc.com/docs/standards/sar/Revised_V3_Implementation_Plan_Clean_2010Feb12.pdf (undated webpage).

[497] NERC--North American Electric Reliability Corporation. April 2013 Compliance and Monitoring and Enforcement Program, 2012 Annual Report. Accessed October 21, 2013 at http://www.nerc.com/pa/comp/Reports%20DL/2012_CMEP_Report_Rev1.pdf

[498] NERC--North American Electric Reliability Corporation. January 2011. Compliance Trending. Accessed October 21, 2013 at http://www.nerc.com/pa/comp/Compliance%20Violation%20Statistics%20DL/Decemeber%20Statistics%20Complete.pdf

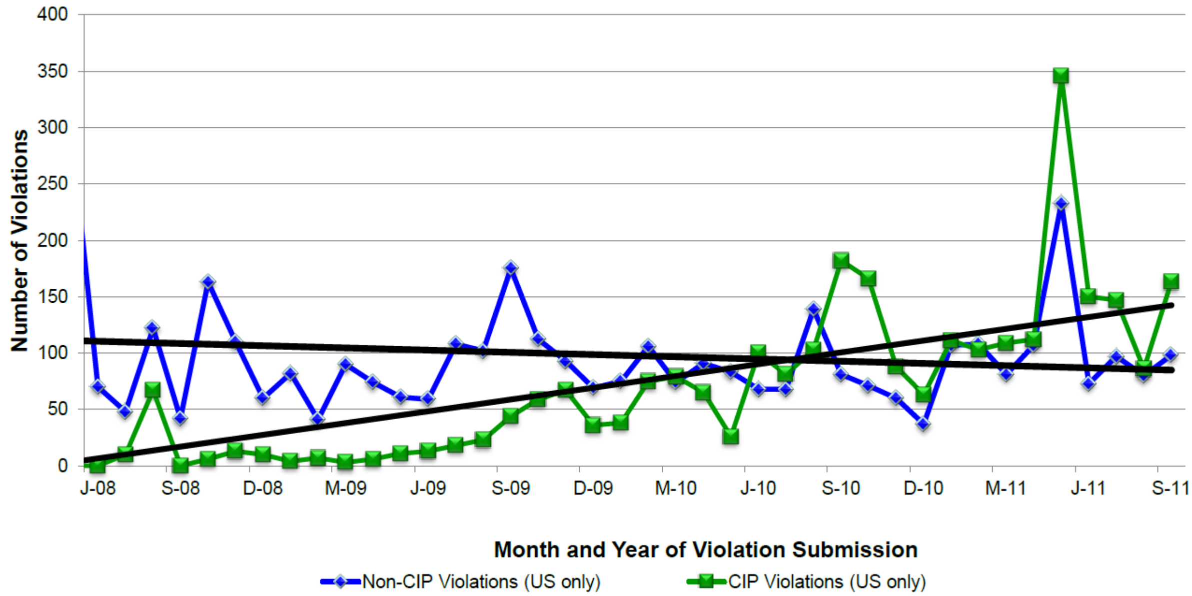



**Figure A.66**. CIP vs. Non-CIP Violation Trend[499]

For the period of April 1, 2011 to March 30, 2012, seven of the top 12 violated active or closed FERC enforceable standards were CIP-002 through CIP-009 standards, the most violated being CIP-007, CIP-005, and CIP-006 (see Figure A.67).

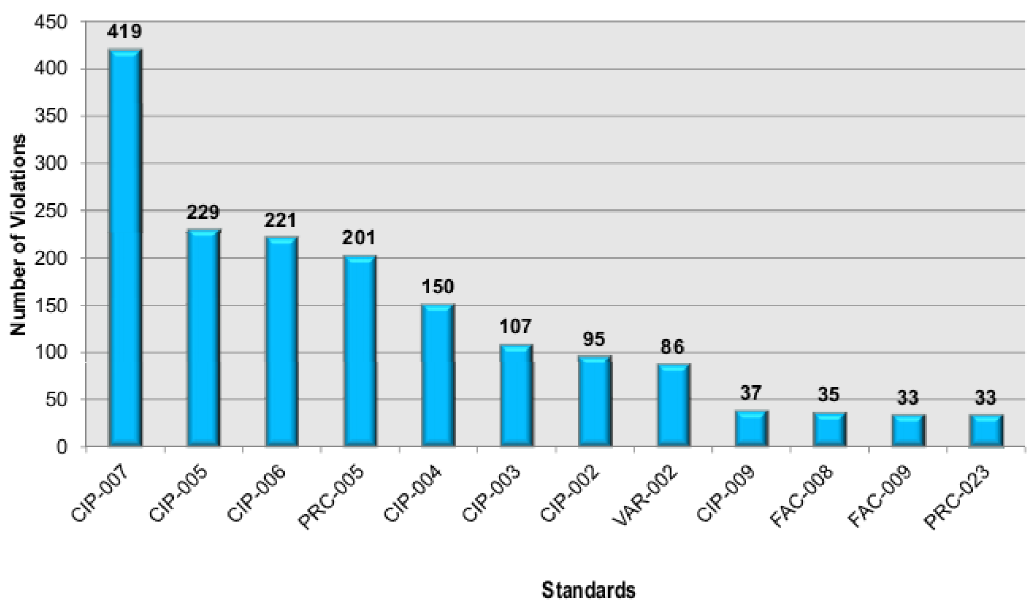



**Figure A.67**. Top 12 Enforceable Standards Violated (Active and Closed) from April 1, 2011 through March 30, 2012

[499] NERC – North American Electric Reliability Corporation. 2011. *Quarterly Statistics Item*. Accessed June 11, 2012 at http://www.nerc.com/files/BOTCC-November_Open_%20BOTCC%20slides%201122011%20FINAL.pdf (undated webpage).

Figure A.68 shows the CIP and non-CIP work violations for all the NERC regions. As shown, the WECC reported high levels of violations in 2011 and 2012 as did the SERC Reliability Corporation. The NERC work violations peaked in the Reliability *First* Corporation (RFC) in 2011.

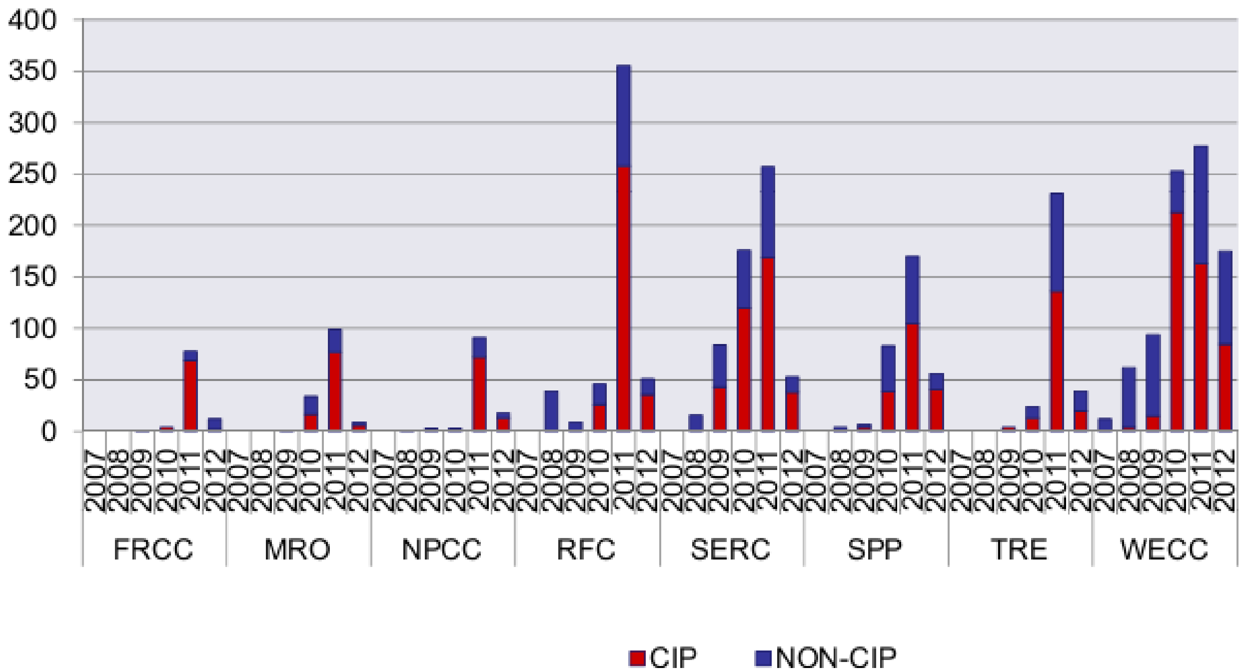



**Figure A.68**. NERC Work Violations for CIP and Non-CIP from 2007 to March 2012 across Regions.[500] (FRCC = Florida Reliability Coordinating Council; MRO = Midwest Reliability Organization; NPCC = Northeast Power Coordinating Council; RFC = Reliability *First* Corporation; SPP = Southwest Power Pool, RE; TRE = Texas Regional Entity).

Interviews of 30 electricity service providers (Appendix B) included questions about specific security measures that utilities are implementing. The results are shown in Table A.25. Of those electric service providers interviewed for this study, 50 percent deploy intrusion detection technologies (down from 62.5 percent reported in 2010), while 46.7 percent have key management systems (down from 50 percent), 50 percent utilize encrypted communications (down from 66.7 percent), and 63.3 percent have firewalls established to secure their systems (down from 91.7 percent). While these new numbers are a matter for some concern, it is reasonable to assume that the decreases found are a reflection of the relatively small sample of respondents to these questions (about half of the 30 companies) and do not reflect a general trend.

[500] NERC – North American Electric Reliability Corporation. 2012d. *Key Compliance Trends Item 2a*. Accessed June 11, 2012 at http://www.nerc.com/files/041012_Public%20Posting%20of%20Stats.pdf (undated webpage).

**Table A.25**. Security Question from Electricity Service Provider Interviews

| Have you deployed the following security features? (*Select all that apply*) | Affirmative Response |
|---|---|
| a. Intrusion detection | 50.0% |
| b. Key management systems | 46.7% |
| c. Encrypted communications | 50.0% |
| d. Firewalls | 63.3% |
| e. Others | 12.5% |

While compliance with mandatory security standards is an important step toward achieving security, it is in itself not a complete measure of security. Generally, these security standards are more focused on compliance requirements, and increased compliance may not necessarily equate to increased security. Furthermore, standards can take years to develop and implement and may lag behind the cutting edge of technology deployment, particularly when the industry is in transition, as is the case with smart grid technologies. Therefore, these metrics may be more of lagging rather than leading indicators of the security posture of the smart grid.

Electric power control systems evolved in an environment of implicit trust. A properly formatted command is carried out without question by the automatic controller. In this environment, security relies on isolation. Over the years, the electricity industry built and operated its own private communications infrastructure to control the electric power grid, using systems and protocols unique to the industry. Noise, interference, and equipment reliability were the primary issues to overcome. The isolation that resulted gave rise to a belief that the system was inherently secure. However, it was also expensive to implement and maintain, and it was not easy to adopt new technologies.

There has been a recent trend toward sharing communication with public networks, using open and commonly used protocols, and general-purpose operating systems. The security weaknesses of such networks are widely known because of careful technical analysis performed by experts in their fields. Economic forces and technology development are making the power system more dependent on information systems and associated communications networks, particularly in the context of smart grid systems and their inclusion of demand-side resources. The interconnected nature of these communications systems and the need to continue supporting older legacy systems in parallel with newer generations of control systems further compound the complexity and challenges of addressing this problem.[501]

In addition, data exchange interactions between businesses result in handing of data security responsibility at the interface between the interacting parties. Ensuring that information privacy is protected and that cybersecurity vulnerabilities are addressed on either side of an interface requires a coordination of business processes, particularly when the data may transition to different technologies and protocols. Designed-in security approaches are emerging, however. Unlike the threats from component failures, extreme weather or natural disasters that are mitigated by highly effective and well-developed contingency and restoration practices, the cyber-threat landscape is beginning to be addressed through common industry standards and practices.

[501] NERC 2010b.

To assist utilities in forming a better understanding of cybersecurity risks, and to provide a tool that can be used to assess the severity of such risks and identify approaches to managing the risk, the U.S. Department of Energy (DOE) and the NIST working in collaboration issued their Cybersecurity Capability Maturity Model. The Version 1.0 report, which was published in 2012, defines the threats associated with cybersecurity, outlines a modeling approach, presents the model architecture, and provides an overview of how to use the model.[502]

#### A.18.3.1 Associated Stakeholders

Cybersecurity is of importance to a broad group of stakeholders, including:

- End-users – Cybersecurity breaches can greatly affect consumers, not only from disruptions when the electric infrastructure is compromised, but also because a smart grid incorporates participation by consumers' automation systems. Electricity-related information technology connectivity may provide a new path for a cyber-attack that might affect a facility's operation or obtain private information. Each consumer group needs to assess its vulnerability and develop an appropriate security posture.
- Electric service retailers and wholesale electricity traders – These entities connect to customer systems, market operators, and infrastructure system operators with greater linkages as smart grid trends progress. Security issues must be assessed across their operations with cooperation between all transacting business systems.
- Distribution and transmission service providers, balancing authorities, and reliability coordinators – The protection of the infrastructure is a national concern. The NERC CIP requirements, while modest, are being refined with recognition of the importance of security.
- Products and services suppliers – Vendors of information technology, business systems, and engineering have shown interest in developing or updating product offerings to address security needs. However, real change occurs when customers specify security features as requirements for their purchases.
- Energy policy makers and advocates – The idea that the electric infrastructure could be crippled by a cybersecurity breach is disconcerting to those protecting the public interest. Policy makers are searching for ways to ensure that cybersecurity issues are addressed. For example, NERC continues to strengthen the CIP standards, as the balance between cost, risk, and effective measures continues to mature.

#### A.18.3.2 Regional Influences

Approaches to cybersecurity should not vary greatly across nations, on a technical basis, relative to hardware and software. State-specific issues may arise because of different laws relating to transparency of information associated with *Freedom of Information Act* issues. For example, in California, a state-sponsored organization such as the California Independent System Operator may find it difficult to protect sensitive information from being disclosed because of state sunshine laws. There will also continue to be international and national standards in the cybersecurity area that may compete in technology and policy approaches.

[502] DOE and DHS – U.S. Department of Energy and U.S. Department of Homeland Security. 2012. *Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2)*. Version 1.0, Washington, D.C.

### A.18.4 Challenges to Deployment

#### A.18.4.1 Technical Challenges

The electricity system of the future could become more vulnerable to disruption by skilled electronic intrusion originating either internally or externally. Compounding the problem, security has often been neglected or introduced as an afterthought rather than being incorporated as a core component in the development and deployment of these new technologies and applications.

Because cybersecurity is largely a defensive practice when applied to protecting against a steady flow of active exploits, the threat to computer and control systems is never completely ameliorated. A vital need in the electricity industry is the development of new approaches for inherent security—components and systems with built-in security capabilities. Coordination is also needed between these approaches and techniques appearing in other industrial, commercial building, and residential systems that interact with the electricity system. Resources, such as adequately trained staff to design and implement the standards, will present challenges in the first few years. [503]

The complexities and interdependencies of cybersecurity elements are not uniformly understood throughout the power industry. The complexities include internal and external issues with the electricity infrastructure. Examples of internal interdependencies are market-based systems for buying, selling, and wheeling power throughout the network; while they are not directly connected to the control systems providing real-time operation of the grid, there are sometimes subtle dependencies that could cause reliability implications if security in these systems were compromised. An example of an external interdependency is reliance on other infrastructures, such as communication, that are vital to the operation of the electricity infrastructure. Systemic failures that propagate among these dependency seams can create failure modes that are difficult to predict and mitigate.

Finally, it is not clear whether there is general consensus among the industry stakeholders regarding the threat, which leads to inconsistent views about the appropriate level of attention and investment needed to achieve appropriate levels of security.

#### A.18.4.2 Business and Financial Challenges

The key challenge will be to maintain reliability in a vastly more "connected" electric industry under threats that could involve multiple, distributed, and simultaneous or cascading incidents—whether accidental or deliberate. Steps should be taken to enhance the security of real-time control systems using sound information security practices. In the future, the goal should be that all control systems for critical applications are designed, installed, operated, and maintained to survive an intentional cyber assault with no loss of critical function.

All stakeholders share a common interest in deterrence, intrusion detection, security countermeasures, graceful degradation, and emergency backup and rapid recovery. While the NERC CIP-002 through CIP-009 standards are an effective start to begin addressing cybersecurity and are achieving increased

[503] Dyonyx. 2009. *Top Ten Issues for Implementing The NERC CIP Reliability Standard*. Accessed August 2, 2012 at http://www.dyonyx.com/about-us/resources/top-ten-issues-for-implementing-the-nerc-cip-reliability-standard.aspx (undated webpage).

awareness and action within the electricity service provider industry, there is growing recognition, based on NERC's reporting of noncompliance, that they have not yet achieved their ultimate purpose: defining uniform standards that, if implemented, can provide adequate security against cyber-threats to the electric infrastructure. Problems with the standards include provisions for entities to self-define what they will protect and how they will protect it; this has resulted in a patchwork of mitigation measures that is more focused on compliance than security. In addition, there is concern that the standards have loopholes associated with communications and certain types of control systems. Given the evolving nature of the technologies involved and the nascent deployment of the processes, there is a constant need to keep updating and moving to newer versions of the standards, as has been the case. More work to transition the industry mind-set from a culture of compliance to a culture of security is necessary.

Another issue is inconsistent regulatory support that electricity service providers have associated with cost recovery for necessary security enhancements. The electricity regulatory landscape is complex, with multiple stakeholders at the federal, state, and local levels. Not all regulatory jurisdictions have recognized security as a recoverable cost, and other electricity service providers are constrained in implementing security because it would cause pre-existing rate cases to be reopened at great expense and risk to the company. The matters of public versus private electricity service provider ownership, small numbers of very large utilities and large numbers of small utilities, and widely varying regulation are also implementation challenges. Additionally the standards have come well after some of the technology was developed and put in the field. For example, NIST has developed 3 volumes providing guidelines for smart grid cyber security.[504, 505]

## A.18.5 Recommendations for Future Measurement

Newer versions of the NERC CIP standards are evolving and their implementations are being planned. The audit results are also being reported on a monthly basis, which makes the nationwide trends in deployment easy to assess. Hence, it would be beneficial to stay with this trend of constant standards evolution and timely audit results reporting. In using NERC CIP compliance results, care should be taken to realize that the results do not include many of the utilities and other organizations implementing smart grid solutions; only those participating directly in the bulk power system are represented by these metrics.

In addition to the NERC CIP standards, efforts specifically focused on cybersecurity for smart grid implementation have been underway for the past few years. The DOE Office of Electricity Delivery and Energy Reliability released guidelines for the electricity subsectors in its cybersecurity risk management process (RMP). This collaborative effort with the NIST, NERC, and a significant number of industry and utility-specific trade groups resulted in the creation of a tailorable RMP that could effectively meet the stringent organizational requirements throughout the electric subsectors' generation, transmission, and distribution environments. It has also been crafted to be extended into the electricity market and supporting organizations such as vendors and suppliers. The process is designed to improve cybersecurity resource allocation, operational efficiencies, and the ability to mitigate and rapidly respond to cybersecurity risk. The RMP leverages the larger stakeholder community by facilitating information

[504] NIST – National Institute of Standards and Technology. 2010b. Guidelines for Smart Grid Cyber Security: Vol. 1, Smart Grid Cyber Security Strategy, Architecture, and High-Level Requirements: Vol. 2: Privacy and the Smart Grid; Vol. 3, Supportive Analysis and References, NISTIR 7628. Accessed November 9, 2012 at http://csrc.nist.gov/publications/PubsNISTIRs.html#NIST-IR-7628 (last updated May 13, 2014).

[505] Johnson, M, D Danielson, I Gyuk 2010. "Grid Scale Energy Storage." Presentation at ARPE-E Pre-Summit Workshop.

exchanges between other critical infrastructure and key resource domains, and private, federal, and international entities (Canada and Mexico).

The National Board of Information Security Examiners (NBISE) was formed with a mission to increase the security of information networks, computing systems, and industrial and military technology by improving the potential and performance of the cybersecurity workforce. NBISE leverages the latest advances in assessment and learning science towards the solution of one of the United States' most critical workforce shortages: cybersecurity professionals. Through its Advanced Defender Aptitude and Performance Testing and Simulation program, NBISE coordinates practitioners, researchers, and educators, which develop and validate or enhance existing performance-based learning and assessment vehicles.

The National Rural Electric Cooperative Association has developed guidance documents to help utilities develop cybersecurity programs, and the Department of Homeland Security (DHS) has established ICS-CERT, which reports on vulnerabilities found within control systems. While trending the number of vulnerabilities found may be of limited value in measuring the overall security of the smart grid, it does provide an indicator of the security effort being employed in control systems of which smart grid is a component. Incident reporting would be a useful part of assessing cybersecurity measure effectiveness.

In January of 2012, a White House initiative led by the DOE created the Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2).[506] The goal of this model is to support ongoing development and measurement of cybersecurity capabilities within the electricity subsector. DOE participated in a series of onsite asset owner assessments using the ES-C2M2 tool, which reported significant success and support of all participant sites involved. This tool will help measure the progress in implementing strategies outlined in DOE's "Roadmap to Achieve Energy Delivery Systems Cybersecurity," which over the next decade will provide a framework for designing, installing, operating, and maintaining a resilient energy delivery system capable of surviving cybersecurity incidents while maintaining critical functions.[507]

The DOE also hosted onsite engagements to ensure participants had qualified resources fully available to them to overcome certain questions related to their implementation areas. Facilitated annual cybersecurity workshops also provided a valuable and highly attended collaboration environment where cybersecurity experts and program stakeholders could exchange best practices and lessons learned. Online resources such as www.arrasmartgridcyber.net provided guidance to foster a non-prescriptive and flexible approach for participants to customize their cybersecurity programs commensurate with their specific project characteristics and requirements.

Under ARRA, SGDP grant recipients were required to address cybersecurity challenges by creating a project-specific cybersecurity program and implementation plan. Each participant addressed core programmatic elements, including roles and responsibilities, cybersecurity risk management, defensive strategies, security controls, incident response and recovery, development lifecycle, policies and

---

[506] DOE and DHS 2012.

[507] DOE – US Department of Energy. 2011a. Roadmap to Achieve Energy Delivery Systems Cybersecurity. Washington, D.C. Accessed May 31, 2013 at http://energy.gov/sites/prod/files/Energy%20Delivery%20Systems%20Cybersecurity%20Roadmap_finalweb.pdf. (undated webpage).

procedures, and training. DOE Smart Grid Investment Grant recipients are also required to develop cybersecurity plans. Each year for the three years of the grant plus an extra two years there is a review of each grantee's cybersecurity plan and implementation. This information could be analyzed and used for trending cybersecurity within the smart grid. Finally, the NIST/Smart Grid Interoperability Panel Smart Grid Cybersecurity Committee has produced NIST-IR 7628, "Guidelines for Smart Grid Cyber Security." Version 1.0 of this three-volume report was issued in August 2010. A draft update has been produced and is in the public comment/review process.

A more mature evaluation of cybersecurity will evolve toward self-assessment or possibly third-party certified tools to provide enduring capabilities for vendors, system integrators, and asset owners to afford appropriate security commensurate with the risk associated with the application. The industry can then be responsible for making its own reasoned and informed tradeoffs. Related metrics include identifying the percentage of the distribution-level utilities having a cybersecurity compliance program, identifying percentages of state utility commissions that include cybersecurity provisions in their requirements, and the inclusion of cybersecurity requirements in vendor solicitations.

It may also be possible to determine the percentage of authoritative bodies (e.g., state utility commissions, municipal and co-op oversight groups) that require or strongly reference cybersecurity for their respective constituents. These data have seemingly not been collected to date.

# A.19 Metric #19: Open Architecture/Standards

## A.19.1 Introduction and Background

Straightforward integration of new components is essential to the success of the smart grid. Given the likely abundance and variety of such components, the integration methods must converge to a few commonly supported practices. They must be scalable and they must be standardized. Although such methods will change in detail as technology solutions advance, success in achieving objectives at the local, regional or national level will depend on a level of stability for interface definitions.

The term "open" in the title of this section is intended to mean that the specifications, methods, and resources that facilitate system integration are accessible to all interested parties, and do not become barriers to entry for new participants. The widespread adoption of openly available standards and architectural approaches is an indication of maturity in technology and business practices. Smart grid implementations generally include some immature technologies. There are many separate companies involved, each with its own heritage in business practices and standards. A reduction in the number of methods in use may eventually come from the large penetration of Internet-based technology and methodologies, but it will take time to develop and materialize. A culture of continuous convergence is needed to advance interoperability in an open society.

Software development has gone through a process that is similar to the one anticipated for the smart grid. At one time, there were many methods, languages, and processes for developing software in different communities, with different levels of success in different applications. Rather than pick a "winner," the Software Engineering Institute (SEI) at Carnegie Mellon took the approach of encouraging a culture of continuous process improvement. The result is the SEI Capability Maturity Model Integration, a process improvement approach.[508]

A concept similar to this is being advanced by the GridWise® Architecture Council (GWAC), a group formed by the U.S. Department of Energy in 2004[509] with the goals of engaging stakeholders and identifying concepts and architectures to make interoperability possible. The GWAC is developing a smart grid interoperability maturity model (SGIMM) for application to smart grid products and project implementations. The model is intended to facilitate developing methods and processes that improve the integration of automation devices and systems. In addition, the model can be used to create tools for self-evaluation, resulting in recommendations for improving interoperability.[510]

## A.19.2 Description of Metric and Measurable Elements

(Metric 19) Interoperability Maturity Level. The weighted-average maturity level of interoperability realized among electricity system stakeholders.

[508] SEI – Software Engineering Institute. 2012. *CMMI Overview.* Software Engineering Institute, Carnegie Mellon University, Pittsburgh, Pennsylvania. Accessed June 2012 at http://www.sei.cmu.edu/cmmi/ (undated webpage).

[509] GridWise® Architecture Council. 2012. *GWAC Mission and Structure*. Accessed August 3, 2012 at http://www.gridwiseac.org/about/mission.aspx (undated webpage).

[510] Widergren S, A Levinson, and J Mater. 2010. "Smart Grid Interoperability Maturity." In *Proceedings of the 2010 PES General Meeting*, July 25-29, 2010, Minneapolis, Minnesota, IEEE Power & Energy Society, Piscataway, New Jersey.

The SGIMM model may be summarized as shown in Figure A.69.

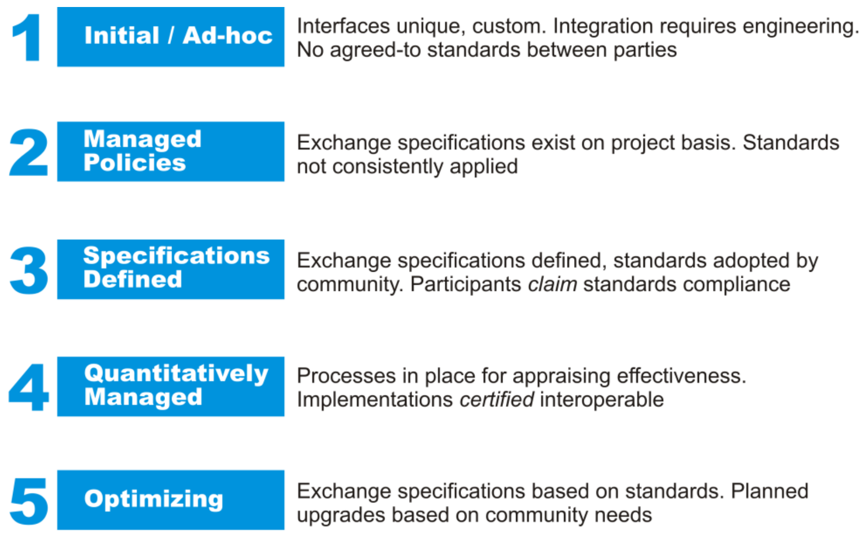



**Figure A.69**. SGIMM Maturity Levels

The progression may be thought of as follows:

- At Level 1, the "Initial/Ad-hoc" level, interface areas are unique and usually custom-developed. Components at this level require significant custom engineering to integrate with other components. There may be no agreed-upon standards between parties. Interoperability is difficult to achieve and very expensive to maintain.
- At Level 2, the "Managed Policies" level, exchange specifications and testing processes exist on a project basis, but are not defined for the larger community. Some standards may be referenced or emerging, but may not be consistently applied.
- At Level 3, the "Specifications Defined" level, exchange specifications are defined above the level of a project, and use standards adopted by the community. Well-developed interoperability verification regimes are in place. Participants claim standards compliance for their equipment.
- At Level 4, the "Quantitatively Managed" level, processes for appraising the effectiveness of specifications and standards are in place. The processes are supported by the community: successes and deficiencies are noted. Implementations are certified to be interoperable.
- At Level 5, the "Optimizing" level, specifications for interoperability are based on standards. A process of continuous improvement is in place. There are planned upgrade processes driven by quantitative feedback from implementations and the needs of the community.

The method for measuring progress in open architecture and standards is first to develop the SGIMM and then survey interactions between stakeholders. This process will allow us to measure the interoperability maturity level in specific smart grid areas that emphasize the interfaces between organizational boundaries. Examples of these boundaries include interfaces between an electricity service provider and residences, commercial buildings, and industrial plants. Another is the interface between a balancing authority and a reliability coordinator.

### A.19.3 Deployment Trends and Projections

The scope of the smart grid includes the transmission and distribution (T&D) areas (such as substation automation), the control centers, and the consumer-side resources. An open architecture that supports the integration of a heterogeneous mix of technologies is desirable for all of these elements. Information exchange may be supervisory control and data acquisition (SCADA) information sharing with other applications, or between operating organizations. Customer-side equipment such as distributed generation, storage, and end-use resources also exchange information. Efforts have been underway for some time to integrate equipment and systems in substation automation, control centers, and enterprise systems, and within industrial, commercial-building, and residential energy management systems. The level of integration is increasing in each of these areas, as is the amount of integration between them. Responses to survey questions regarding the level of maturity (see Appendix B) are shown in Figure A.70.

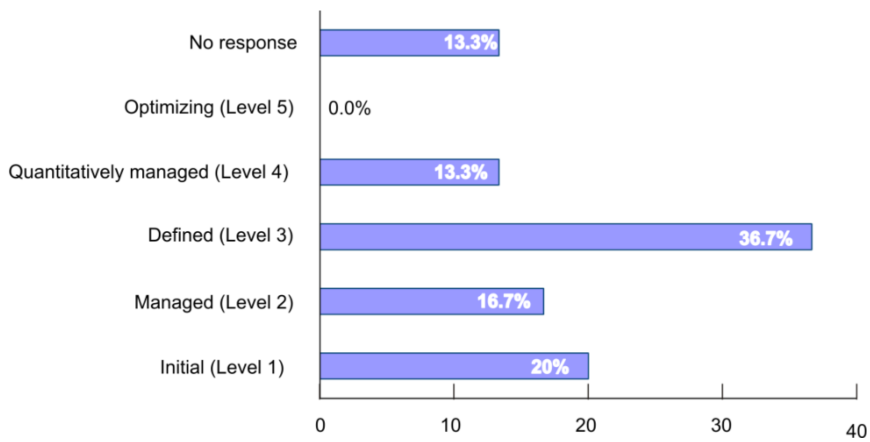



**Figure A.70**. Reported Levels of Interoperability Maturity

These figures were not reported in the 2010 Smart Grid System Report, so there is no way now to see a trend. However, it is worth noting that more than a third of the respondents had achieved Level 3.

In 2007, the matter of integration was formally made part of the responsibility of the National Institute of Standards and Technology (NIST). Under the *Energy Independence and Security Act of 2007* (EISA), NIST has "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems." NIST, with $17 million in *American Recovery and Reinvestment Act of 2009* (ARRA) funding, has since published a framework and roadmap for smart grid interoperability.[511]

In November 2009, NIST formed the Smart Grid Interoperability Panel (SGIP) and encouraged smart grid stakeholders from all organizations associated with electric power to establish this community with the goal of advancing interoperability through jointly defining goals, performing gap analyses, and prioritizing efforts to take on the challenges to integration.

[511] NIST – National Institute of Standards and Technology. 2010. *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0*. NIST Special Publication 1108, Office of the National Coordinator for Smart Grid Interoperability, Gaithersburg, Maryland. Accessed July 16, 2010 at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf (undated webpage).

NIST has worked to foster an open and regular means of collaboration among domain experts, with the overall goal of advancing smart grid interoperability. In April 2009, NIST awarded a contract to EPRI to facilitate two stakeholder workshops. Following a series of such workshops, NIST issued Special Publication 1108, the *NIST Framework and Roadmap for Smart Grid Interoperability Standards,* Release 1.0. This document identified 75 standards that can be applied or adapted to smart grid interoperability or cybersecurity needs. It identified priority action plans to address 16 standardization gaps and issues.

The February 2012 Release 2.0 of *NIST Framework and Roadmap for Smart Grid Interoperability Standards* adds to the 2010 work a further 22 new standards, specifications, and guidelines. The Release 2.0 Framework lays out a plan for transforming the nation's electric power system into an interoperable smart grid. Improvements and additions include:

- a new chapter on the roles of the SGIP
- an expanded view of the architecture of the smart grid
- a number of developments related to ensuring cybersecurity for the smart grid, including a risk-management framework to provide guidance on security practices
- a new framework for testing the conformity of devices and systems to be connected to the smart grid—the *Interoperability Process Reference Manual*
- information on efforts to coordinate the smart grid standards effort for the U.S. with similar efforts in other parts of the world
- an overview of future areas of work, including electromagnetic disturbance and interference, and improvements to SGIP processes.[512]

A "Catalog of Standards" has also been released by the SGIP. This catalog is anticipated to provide an important source of input to the NIST process for coordinating the development of a framework of protocols and model standards for the smart grid under EISA responsibilities. As of June 2013, the current catalog contains 56 standards that have been submitted and approved for inclusion by a super-majority of the Smart Grid Interoperability Panel (SGIP) participating members.[513]

In addition to NIST producing a smart grid interoperability standards roadmap, EPRI is developing the IntelliGrid[SM] architecture, which is a methodology for capturing system requirements and designing approaches for electric utility enterprise integration. The IntelliGrid program is designed to provide a set of methods, tools, and recommendations to electricity service providers for deploying systems including distribution automation, demand response, wide-area measurement, or advanced metering.[514]

Standards and openness are also advancing in terms of the layers of agreement that must align. The SGIMM proposes three major categories that must be aligned to achieve interoperability: technical,

[512] NIST – National Institute of Standards and Technology. 2012a. *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0.* NIST Special Publication 1108R2, Office of the National Coordinator for Smart Grid Interoperability, Engineering Laboratory, Gaithersburg, Maryland. Accessed August 3, 2012 at http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf (undated webpage).
[513] NIST – National Institute of Standards and Technology. 2013. *SGIP Catalog of Standards*. Smart Grid Interoperability Panel Site. Accessed July 1, 2012 at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/SGIPCatalogOfStandards#Overview (last updated June 6, 2013).
[514] NIST 2012a.

informational, and organizational. Within these, the model identifies ten cross-cutting issue areas that can be gathered into three issue areas:

- Configuration & Evolution:
  - Shared Meaning of Content
  - Resource Identification
  - Discovery & Configuration
  - System Evolution & Scalability
- Operation & Performance:
  - Time Synchronization & Sequencing
  - Transaction & State Management
  - Quality of Service
- Security & Safety:
  - Security & Privacy
  - Logging & Auditing
  - System Preservation

In addition, the model identifies eight interoperability categories that can be gathered into three interoperability categories, as follows:

- Organizational:
  - Economic/Regulatory Policy
  - Business Objectives
  - Business Procedures
- Informational:
  - Business Context
  - Semantic Understanding
- Technical:
  - Syntactic Interoperability
  - Network Interoperability
  - Basic Connectivity

Figure A.71 represents the SGIMM. It illustrates the three framework categories, the three issue areas, and the general goals for each intersection. Of course, the relative achievement of each of these goals will change with the maturity of the technology.

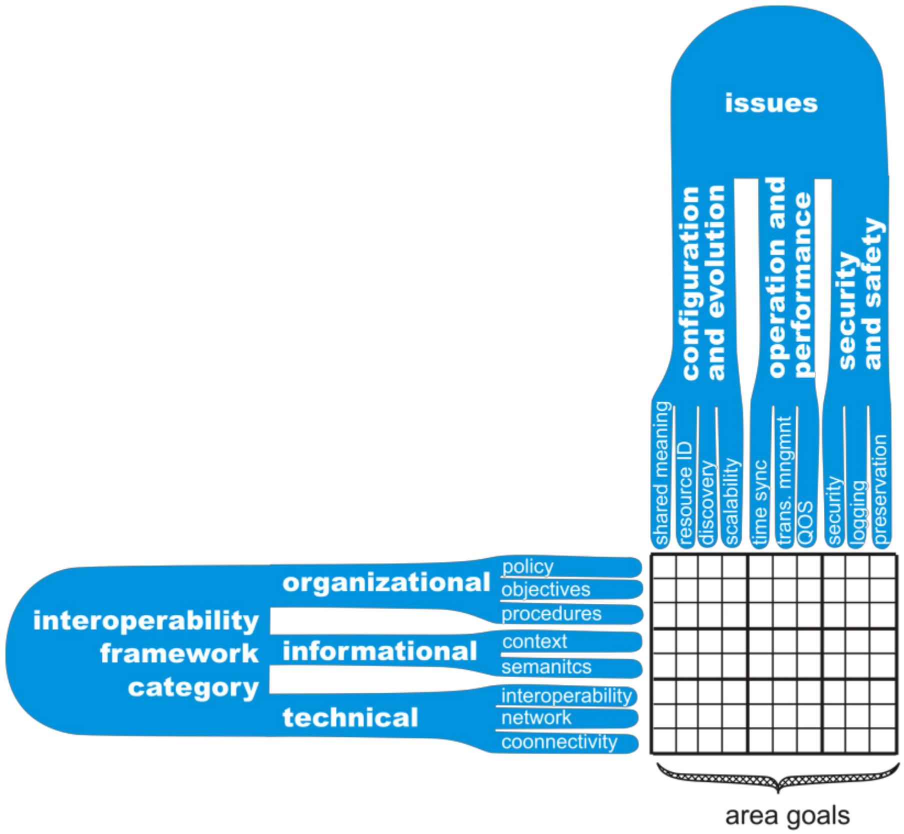



**Figure A.71**. Interoperability Categories

The model is intended to enable the user to focus attention on the high level or the detailed level of analysis. To dig deeper into interoperability areas, the category and issue axes can be used to guide users to issues that are more specific.

The technical categories involve network connectivity and syntax. There are many lower-level protocols to handle communications networks (e.g., cable, twisted pair, fiber optics, wireless, broadband power line carrier), and protocols with associated syntax (e.g., Ethernet, TCP/IP, ZigBee®, IEEE 802.11, Wi-Fi). The standards for these technologies are mature. Often an assortment of communications products is procured and integrated to support many applications. Layered on top of these communications networks are general purpose application protocols to support SCADA activities. There is a trend to move away from proprietary communications networks, protocols, and syntax toward widely available standards supported by various product offerings.

The information categories are less mature than those in the technical area. The SCADA information models tend to generically describe equipment, measurements, and actuators. The understanding of the equipment and how it fits within a business process is held in specification documents, and in the minds of the programmers and integrators. Thus, there is a high level of customization for each application. Anything approaching standardization is contained in "best practices." Exceptions to this exist with a few automation interface standards.

However, the standards emerging to support e-commerce are making significant progress with modeling the information for specific business contexts. The Internet-based information-modeling standards (e.g., Extensible Markup Language [XML], Unified Modeling Language [UML], Resource Description Framework [RDF], and Web Ontology Language [OWL]) dominate the new standards work.

The organizational categories involve business operations and strategic decision-making. In this area, business processes are modeled using methods that are supported by enterprise integration and e-commerce tools and modeling techniques. These methods represent humans and machines as abstract concepts that reflect the series of actions involved in a business process. Where each human or machine application interfaces with another, the sequence, performance, information exchanged, and consequences under failure scenarios are captured in a specification. Languages continue to evolve to record these specifications and mechanically turn appropriate aspects of them into software-interface definitions and code. In particular, web services and service-oriented architecture techniques are being employed to support these higher-level concepts. Business process modeling has been virtually nonexistent in consumer-side electricity-related automation and T&D automation. It is appearing in control centers, particularly as the interface to other applications of the enterprise.

In the technical categories of network connectivity and syntax, multiple standards will continue to evolve to support the various communications media. However, bandwidth is becoming less of a problem, and Internet-based approaches are likely to continue to grow as hardware and software tools make them more cost-effective.

Convergence toward information modeling using UML, XML Schema, and the OWL semantic language is gaining ground. With the advent of web services and service-oriented architecture, tools and techniques for designers and implementers are making it easier to move into business-process modeling.

In May 2012, the IEEE announced the release of Standard 802.15.4g—the latest in the series of standards for local and metropolitan area networks. This particular standard is for the physical layer of communications between certain smart grid devices, including smart meters and smart home appliances. This standard is an important fundamental standard for the large-scale networks that characterize the smart grid. The standard's specifications for wireless communications will allow millions of devices to interoperate. The standard is already supported by products from a large number of global vendors and is expected to gain worldwide adoption rapidly.[515] ZigBee 2.0 is another wireless standard currently being finalized. It is popular in smart metering communications, with end-use devices, and in facility energy management systems.

### A.19.3.1 Stakeholder Influences

As Figure A.71 suggests, nearly all stakeholders are affected by the availability and adoption of integration architectures and supporting standards. In particular, the following groups are most affected:

- consumers – The amount and reliability of participation of demand-side resources depends on integrating automation systems cost-effectively.

[515] IEEE Std 802.15.4g is available through the IEEE Xplore database.

- electric service retailers – Aggregating demand-side resources for participation in local and area system operations depends on cost-effective automation systems to coordinate with consumer systems.
- distribution and transmission service providers – Cost-effective and reliable techniques require standards. Given the scale and long life of the equipment, approaches must be able to evolve over time and continue to integrate with legacy components.
- balancing authorities, generators, wholesale electricity traders, market operators, and reliability coordinators – These require standard enterprise-integration approaches and e-commerce standards for connectivity.
- products and services suppliers – The maturing modularization of software systems discourages large, proprietary solutions that inhibit future competition with other suppliers. Standards are more commonly put into specifications. In addition, suppliers can be more competitive by integrating their offering with components provided by other suppliers. Less customization can allow for higher levels of productivity.
- regulators and policy makers – Greater levels of standardization and common integration approaches can bring costs down for the consumer and foster competition.

#### A.19.3.2 Regional Influences

Given the global reach of solutions providers, open architecture and standards should be encouraged internationally. Practically speaking, national-standards bodies will probably continue to have differences from their counterparts across the globe, in particular, the U.S., the European Union (EU), Japan, China, and India. With few exceptions, the leading IT standards in use and being developed apply uniformly to all parts of a nation.

The EU Commission is also concerned about standardization. Their Smart Grid Task Force defines a smart grid as "an electricity network that can cost efficiently integrate the behavior and actions of all users connected to it—generators, consumers and those that do both—in order to ensure an economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety." Because the smart grid is so broad in its scope, the number of applicable standards is very large. This is the motivation for collaboration by the three European standards organizations: CEN, the European Committee for Standardization (in French *Comité Européen de Normalisation*), CENELEC, the European Committee for Electrotechnical Standardization, an association of the National Electrotechinical Committees of the European countries, and ETSI, the European Telecommunications Standards Institute.[516]

[516] CEN/CENELEC/ETSI. 2012. *Joint CEN, CENELEC, and ETSI Activity on Standards for Smart Grid*. Accessed May 31, 2012 at http://www.cen.eu/cen/Sectors/Sectors/UtilitiesAndEnergy/SmartGrids/Pages/default.aspx (undated webpage).

## A.19.4 Challenges

### A.19.4.1 Technical Challenges

Architectures are subject to innovation through better ideas. This could suggest that standardization inhibits such innovation. While agreement and adoption of standards eases integration and enables cost-effective implementation, new approaches can bring even greater capability and further cost reductions. Standardization features that focus on interfaces and that support extensions, versioning, and adaptation to newer technologies can help support the need to evolve in the quickly changing world of technology.

The SGIP priority action plans have identified the need for new standards, and several standards development organizations are actively developing these to fill the gaps in enabling smart grid interoperability. Although these standards are still evolving, there is a need to test and validate whether their application would actually ease integration, and thus advance interoperability.

Interoperability is also closely tied with cybersecurity challenges. The interface standards need to address cybersecurity requirements as they are developed and avoid or mitigate retrofitting cybersecurity-related capabilities because they were not considered at the beginning. Legacy standards have suffered from this problem, but new standards efforts recognize the need to address cybersecurity needs at the start and accommodate revisions as threats and risks change.

### A.19.4.2 Business and Financial Challenges

Flexibility is important in picking an architectural approach and associated standards. At the corporate level, typically a heterogeneous mixture of technologies and standards services an enterprise and its business-partner connections. For the smart grid, heterogeneity may continue to apply. A balance must be found among many factors, including the cost to move to new technology and standards, the ability to support multiple standards, the impact on productivity and competitiveness, and the risk associated with a decision. Return on investment is the traditional mechanism to explore these trade-offs. However, it can be difficult to quantify the returns from moving toward solutions that manage risk and offer future alternatives.

Nevertheless, at least some companies think there is future return. Merger and acquisition (M&A) activity for the smart grid sector during the first quarter of 2012 was steady with one-half billion M&A dollars going into six transactions. Top M&A transactions include the acquisition of RuggedCom by Siemens; SmartSynch by Itron; Comverge by H.I.G. Capital; Recurve by Tendril; and Ecologic Analytics by Landis+Gyr.[517]

## A.19.5 Metric Recommendations

Future measurements of progress in this area will depend on the further development of the SGIMM, its deployment, and later, interviews with stakeholders about smart grid applications to investigate the interoperability maturity level in specific areas of interaction. The development of the SGIMM should

[517] Mercom Capital Group, LLC. 2012. *Smart Grid Q1 2012 Funding and M&A – Another Weak Quarter with only $62 Million in VC Funding*. Accessed May 31, 2012 at http://mercomcapital.com/smart-grid-q1-2012-funding-and-ma-another-weak-quarter-with-only-$62-million-in-vc-funding.

identify and include objective criteria and available standards for each of the cross-cutting issues and for interfaces between the domains. Once developed, the SGIMM should be implemented and made available to the smart grid stakeholder community to assess their level of interoperability readiness using a methodical approach.

Whatever approach is taken in refining this metric, it should be expanded to address the security of distribution systems.

# A.20 Metric #20: Venture Capital Investment in Smart Grid Startup Companies

## A.20.1 Introduction and Background

To transition the current power system to a smart grid model, significant investment is required from all sectors. Historically, electricity service providers have been conservative when adopting new and emerging technologies. When considering investment in smart grid technologies, service providers are often challenged by the high cost of investment, nascent stages of technology development and lack of industry standards. A recent analysis determined that the total net investment required over the next 20 years for smart grid development amounts to between $338 and $476 billion.[518] Net benefits of a smart grid are estimated between $1,294 and $2,028 billion,[519] providing unique opportunities for venture capital firms and other investors in smart grid development.

Some companies are poised to develop products based on old designs; smart meters are a good example. Others are creating tools unique to the needs of the smart grid. Without new information technologies to deliver information to utilities and customers, the smart grid cannot be fully realized. In fact, it may be said that information technologies are the backbone of the smart grid.

Venture capital played a major role in creating the biotechnology enterprise, the information technology market and the communications industry. In recent years, venture capital firms have invested increasingly in smart grid technology companies. These venture capital firms have noted several investment drivers, including:

- high oil prices making energy delivered by electricity (produced from all sources) more competitive—the price of oil is recognized as a major indicator of prices in the energy sector, even though oil only produces a small fraction of the electricity in the United States
- peak demand growing at a time when energy infrastructure is in need of updating and replacement
- shrinking capacity margins
- increasing recognition of clean and efficient technologies, including the reduction of carbon dioxide emissions
- stimulus money from the *American Recovery and Reinvestment Act of 2009* (ARRA) supporting smart grid efforts.

Investors have increasingly concluded that these drivers point toward a future that will include smart grid and demand response technologies, and that those who invest early could be rewarded well.[520] Investing in companies focusing on smart grid applications has paid significant dividends to some investors. Figure A.72 demonstrates that the stock performance of a small number of companies

---

[518] EPRI – Electrical Power Research Institute. 2011. *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*. Report 1022519, Palo Alto, California. Accessed June 21, 2012 at http://my.epri.com/portal/server.pt?Abstract_id=000000000001022519.
[519] EPRI 2011.
[520] Quealy JS. 2007. "Financial Market Assessment of Demand Response's Future." In *Southern California Edison Demand Response Forum*, Global Energy Partners, LLC, Lafayette, California.

developing demand response technologies that support the smart grid outperformed the Dow Jones Utility Average Index in the January 2004 – September 2007 time period.[521] The companies highlighted in Figure A.72 include Itron Inc., ESCO Technologies Inc., TeleventGit S. A., Badger Meter, Inc. (BMI), and Roper Industries, Inc.

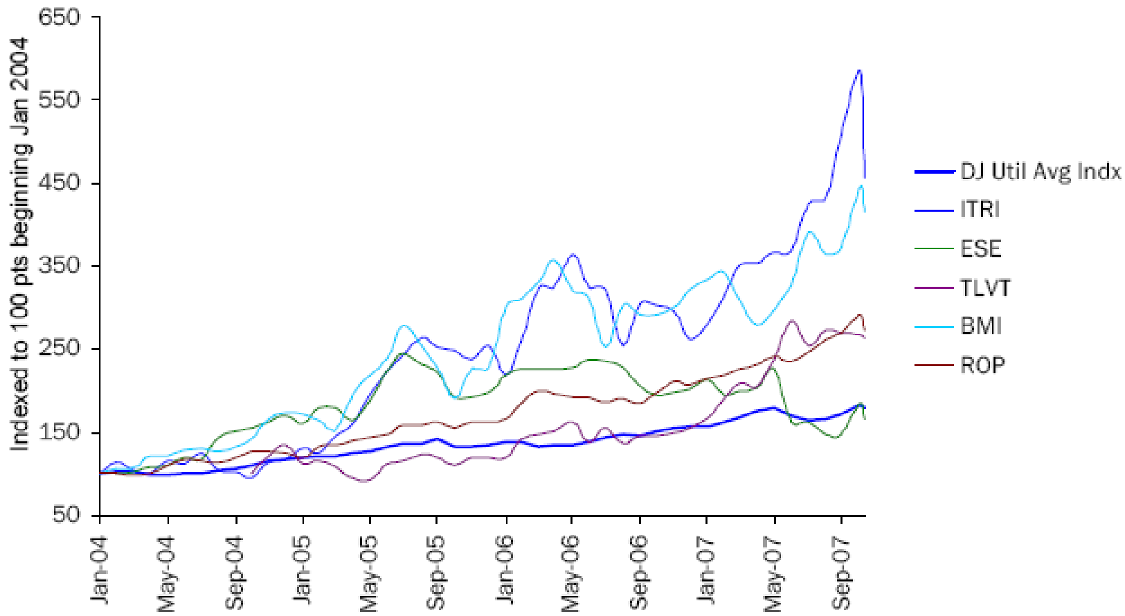



**Figure A.72**. Stock Performance of Companies Developing Smart Grid Technologies

### A.20.2 Description of Metric and Measurable Elements

*(Metric 20a): The total annual venture capital funding of smart grid startups located in the U.S.*

### A.20.3 Deployment Trends and Projections

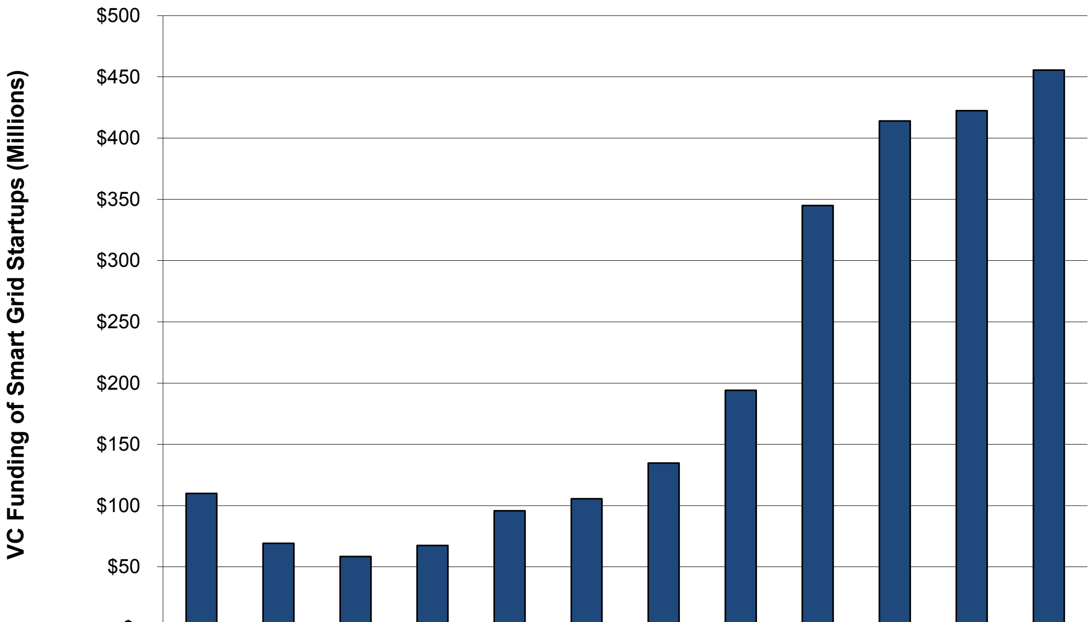
In recent years, investment in smart grid technologies has gained traction. In 2010–2011 alone, numerous venture capital deals were announced, including:

- Silver Spring Networks, a leader in Advanced Metering Infrastructure (AMI), received $24 million.
- Tendril, Inc., a maker of home energy networks, secured $25 million. Tendril recently formed a relationship with automotive manufacturer BMW to develop EV support systems.[522]
- Opower, a company specializing in customer communications systems, secured $50 million.
- Green Plug received $14 million to commercialize its GreenTalk™ technology.
- Control4 received $15 million. Pacific Gas and Electric Company recently selected Control4 to provide smart thermostats for a residential demand response demonstration.[523]

[521] Quealy 2007.
[522] King D. 2012. *BMW, Tendril will Build Demonstration Home 'Wired' for ActivE Electric Vehicle*. Accessed June 10, 2012 at http://green.autoblog.com/2012/01/29/bmw-tendril-will-build-demonstration-home-wired-for-active-ev/.
[523] Fehrenbacher K. 2011. *What You Need to Know About PG&E's Home Energy Projects*. Accessed June 10, 2012 at http://gigaom.com/cleantech/what-you-need-to-know-about-pges-home-energy-projects/.

Venture capital data for the smart grid market for the 2010–2011 timeframe was obtained from the Cleantech Group, LLC. The Cleantech Group's database includes detailed information at the company level; for each transaction, the amount of the transaction, the name of the company, and the company's focus are identified; transactions were stratified by year. Based on these data, venture capital funding secured by smart grid startups was estimated at $422 million in 2010 and $455.4 million in 2011 (Figure A.73).[524]

While growth in smart grid venture capital investment was robust during the 2002–2009 time period, growing at an average annual rate of 32.3 percent, a cautionary note is needed as global investment in clean technologies, including smart grid, dropped in the second half of 2010; venture capital investment in the third quarter was down by 30 percent compared to the second quarter of 2010 and by 11 percent compared to the third quarter of 2009. In 2010, venture capital investment grew by 2.0 percent and in 2011, venture capital investment in smart grid technologies grew by 7.8 percent.




| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| VC Funding | 109.90 | 69.15 | 58.38 | 67.44 | 95.81 | 105.66 | 134.72 | 194.05 | 345.00 | 414.00 | 422.45 | 455.47 |

**Figure A.73**. Venture Capital Funding of Smart Grid Startups (2000-2011)

In a report prepared by the Cleantech Group for the DOE, venture capital spending for the 2007–2010 time frame was allocated to companies by the types of services they provide. The analysis conducted by the Cleantech Group found that more than 50 percent of the venture capital spending in the smart grid space from 2007–2010 went to metering companies (Figure A.74). Home energy management companies received 20 percent of all venture capital spending and building energy management companies received 18 percent during the 2007–2010 timeframe.[525]

[524] Cleantech Group, LLC. 2012. *I3 Platform*. Accessed July 10, 2012 at http://research.cleantech.com/ (undated webpage).
[525] Neichin G and D Cheng. 2010.

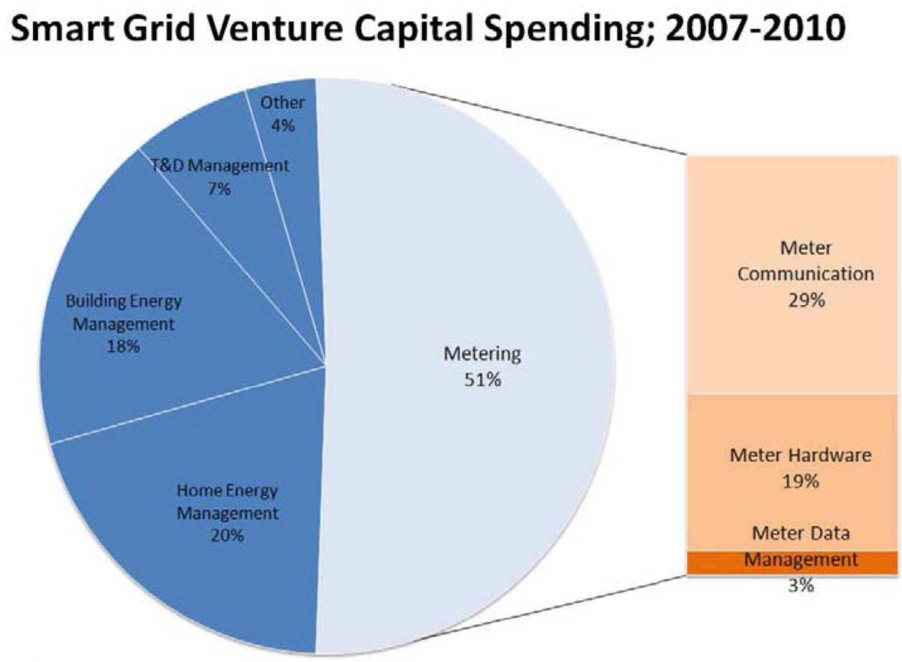



**Figure A.74**. Venture Capital Spending by Company Type (2007–2010)

Table A.26 below provides specific examples of venture capital raised by communications vendors in 2010. These companies have developed AMI technologies such as smart meters, communication technologies and home area networks.

**Table A.26**. Venture-Backed Communication Vendors[526]

| Venture-Backed Communication Vendors (AMI Support) | | |
|---|---|---|
| **Vendor** | **Network Topology** | **Total Venture Capital Raised** |
| Silver Spring Networks | RF Mesh | $247,300,000 |
| Trilliant | RF Mesh | $146,000,000 |
| SmartSynch | Cellular | $30,000,000 |
| Eka Systems (now Cooper Power) | RF Mesh | $31,000,000 |
| Tantalus Systems | Hybrid | $14,000,000 |
| Tropos Networks | Metro WiFi | $81,800,000 |
| | Total | $550,100,000 |

Venture capital is only one source of R&D funding of smart grid companies. Public and private agencies across the U.S. are increasingly investing in the development of smart grid technologies. Since 2004, implementation of renewable portfolio standards, interest in energy efficiency and smart grid technology development have helped to encourage enhanced energy R&D budgets. ARRA-funded efforts include $2.4 billion in programs manufacturing EV support products and $7.2 billion to expand

[526] Cleantech Group 2012.

broadband access and adoption.[527] Figure A.75 identifies 99 Smart Grid Investment Grant (SGIG) demonstration projects underway in 2012, with a total budget of approximately $8 billion. The federal share for these activities is approximately $3.4 billion.[528]


**Figure A.75**. ARRA Smart Grid Investment and Demonstration Projects[529]

### A.20.3.1 Associated Stakeholders

Stakeholders whose actions impact the funding of smart grid startups include:

- regulatory agencies considering smart grid and demand response business cases
- policy makers interested in using smart grid technologies to offset future peak demand growth and reduce the need for investment in supply-side infrastructure
- residential, commercial, and industrial customers who may be skeptical of demand response and smart grid technologies and their effect on future costs and power reliability

[527] DOE – U.S. Department of Energy. 2012a. SmartGrid.gov, "Smart Grid Investment Grant Program" webpage. Accessed June 11, 2012 at http://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.
[528]DOE 2012a.
[529] SGIC – Smart Grid Information Clearinghouse. 2012. "Smart Grid Projects" webpage. Accessed June 8, 2012 at http://www.sgiclearinghouse.org/?q=node/13 (undated webpage).

- electric service providers interested in reducing peak demand and encouraging load shifting
- product and service suppliers in private industry interested in capitalizing on opportunities with smart grid technologies
- venture capital and other investment funds interested in riding the wave of the new technology while yielding potentially significant returns on their investment.

#### A.20.3.2 Regional Influences

Regional influences are reflected in the presence of programs (e.g., time-of-use pricing, advanced metering) and in regulatory structures that advance smart grid investment. Below are specific examples of regional projects underway:

- Pacific Gas and Electric offers an optional SmartMeter™ program allowing customers access to energy use data by logging onto a personal computer. The utility expects to reach full deployment of 5.25 million meters by the end of 2012.[530]
- Florida Light & Power is in the process of deploying AMI systems, distribution automation, new electricity pricing programs, and advanced monitoring equipment for the transmission system to 3 million customers in Florida.[531]
- The Pacific Northwest Smart Grid Demonstration Project is a $178 million program involving five states, eleven utilities, five technology partners, and 60,000 end-use customers. A key attribute of the project is the "transactive control" demand response technology, developed at the Pacific Northwest National Laboratory that bases decisions on a two-way feedback loop between electricity supply and demand.
- Entergy Corporation is installing 4,900 smart meters to test a dynamic pricing system in low-income households.[532]
- CL&P will deploy smart meters for all 1.2 million customers by 2016. CL&P customers will be able to select different pricing structures, including time-of-use pricing and critical peak pricing.[533]

Figure A.76 provides a snapshot of the regional distribution of SGIG projects around the country as of 2012. Total project values range from $132,169 for a demonstration project at the Austin Community College to $688,480,400 for a Duke Energy smart grid project in the Carolinas.[534]

---

[530] PG&E – Pacific Gas and Electric. 2012. "SmartMeter™ Program Updates" webpage. Accessed June 10, 2012 at http://www.pge.com/myhome/customerservice/smartmeter/programupdates/.

[531] DOE – U.S. Department of Energy. 2011. *Florida Light & Power Company: Energy Smart Florida*. Washington, D.C. Accessed June 21, 2012 at http://www.smartgrid.gov/sites/default/files/09-0298-florida-power-light-company-project-description-06-21-11.pdf.

[532] Thompson R. 2010. *Entergy will Roll Out Smart Meters, Giving Low-Income Clients a Way to Track Their Power Usage*. The Times-Picayune, November 1, 2010. Accessed June 10, 2012 at. http://www.nola.com/business/index.ssf/2010/11/entergy_will_roll_out_smart_me.html.

[533] CP&L – Connecticut Light & Power. 2010. *CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis*. Docket No. 05-10-03RE01, Compliance Order No. 4. Accessed June 9, 2012 at http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/recommendations/$File/recommendations.pdf.

[534] Smartgrid.gov. 2012. *Recovery Act Smart Grid Programs: Project Information*. U.S. Department of Energy, Washington, D.C. Accessed June 21, 2012 at http://www.smartgrid.gov/recovery_act/project_information.


**Figure A.76**. Locations of Smart Grid Projects in the U.S.[535]

### A.20.4 Challenges to Deployment

There are a number of barriers to implementing smart grid technologies and these barriers could stall investment. A 2012 survey of industry insiders indicated that the term "smart grid" is undefined, leading to confusion and low customer confidence. In addition, lack of coordination between utilities and regulators has impeded smart grid initiatives, potentially affecting external stakeholders and investment. The greatest impediments to smart grid investments identified by survey respondents are presented in Figure A.77, and include a lack of customer interest and knowledge, funding insecurities due to stimulus money slowdown, and poor business-case justification.[536]

[535] Smartgrid.gov. 2012.
[536] Black & Veatch. 2011. *2012 Strategic Directions Survey Results*. Accessed June 17, 2012 at http://bv.com/survey/2012-electric-utility-survey.

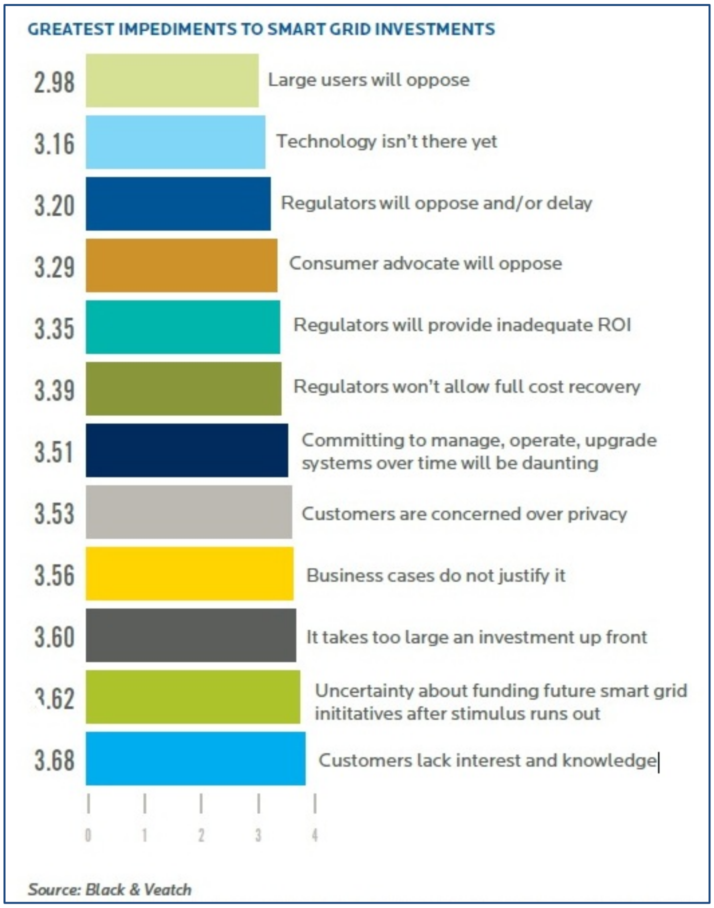



**Figure A.77**. Impediments to Smart Grid Investments[537]

### A.20.4.1 Technical Challenges

Technical barriers include:

- It is too early to pick a technological winner in many smart grid areas, and the lack of a dominant technology generates risk for investors.
- Smart grid companies offering different technology solutions must cooperate with one another to ensure seamless integration.
- Utilities have historically been focused on supply-side solutions and many of the smart grid technologies support demand-side alternatives.
- Consumers are often confused by, and distrustful of, smart grid alternatives offered by utilities (e.g., advanced meters, real-time pricing, appliances that communicate with the grid). Questions have also been raised concerning health impacts due to electromagnetic frequency emissions.

[537] Black & Veatch 2011.

### A.20.4.2 Business and Financial Challenges

Business and financial barriers include:

- The ultimate timing in terms of smart grid technology adoption rates presents a risk to investors who are unwilling to wait 10 to 20 years for an ultimate payoff.
- Regulatory barriers discourage investment in smart grid technologies.
- Cost recovery is a significant challenge. Utilities are facing financial penalties for increasing customer rates to help defray costs related to smart meter deployment. In a 2011 Black & Veatch survey, approximately one-third of utility participants were "unconfident" or "very unconfident" that they would be able to recover cost incurred by smart grid investment.[538]
- Customers are disappointed and non-supportive if predicted savings are not quickly realized.
- Customer privacy issues, including detailed energy consumption records, financial data, and access to e-mail, curtail interest in the smart grid market.
- Utilities operate in markets with little or no competition, so innovation is not ultimately required due to a lack of competing technologies.
- As ARRA funding winds down, projects may end or be delayed if a new source of funding cannot be found.

## A.20.5 Metric Recommendations

The definitions of a smart grid company differ between the firms that track venture capital funding. More consideration should be given to defining what constitutes a smart grid startup, and this definition should be developed, refined, and ultimately held constant over time to allow for trend analysis.

[538] Black & Veatch 2011.

# A.21 Metric #21: Grid-Connected Renewable Resources

## A.21.1 Introduction and Background

A smart grid can be instrumental in allowing grid-connected renewable electricity to provide a significant portion of electricity production. In a carbon-constrained world, the environmental benefits provided by electricity generated from renewables will help reduce the carbon footprint of the electricity generating sector as renewable resources emit significantly lower amounts of carbon dioxide ($CO_2$). Coal-fired electricity generation produces more than 205 pounds of $CO_2$ while natural-gas-generated electricity produces 117 pounds per million British thermal units (Btus) of energy generated. Renewables, on the other hand, produce relatively small quantities of $CO_2$ with only geothermal, at 16.6 pounds, and municipal solid waste, at 91.9 pounds per million Btus, emitting any $CO_2$ as reported by the EIA.[539] Currently, about 4 percent of U.S. electricity production is generated by other renewable energy resources as defined by EIA.[540,541] Conventional hydroelectric is excluded from this metric because it is considered baseload power.

The net benefits that accrue to smart grid applications may, however, be a fraction of the total emissions avoided due to total renewable electricity production. A recent report by PNNL indicates that smart grid applications could allow additional renewable electricity production to reduce annual $CO_2$ emissions by 5 percent by 2030.[542] The relatively small amount of emission reductions in comparison to total avoided carbon emissions occurs because a significant portion of intermittent renewable electricity generation can occur with a very small change in the amount of ancillary services required. The PNNL report indicates that until intermittent generation reaches 20–25 percent only a 0.1 percent increase in frequency regulation is required along with an increase in spinning reserves margin from 5 to 7 percent of load. Another study on integrating wind from the Midwest to the Eastern Interconnection by 2030 indicated that carbon emissions could be reduced by 4 to 33 percent depending on how much wind was brought to market.[543]

However, alternative approaches to smart grid deployment indicate that all renewable-produced electricity, and especially intermittent resources, require smart grid functions today to allow their effective integration. Those smart grid technologies include forecasting and communicating the forecasts for intermittent resource generation on multiple time horizons including day-ahead and hour-ahead

[539] EIA – U.S. Energy Information Agency. November 2011a. "Table A.3: Carbon Dioxide Uncontrolled Emission Factors." In *Electric Power Annual 2010 Data Tables*. Accessed May 23, 2012 at http://www.eia.gov/electricity/annual/html/tablea3.cfm.

[540] EIA – U.S. Energy Information Agency. November 2011b. "Table 2.1.A.: Net Generation by Energy Source by Type of Producer, 1999 through 2010." In *Electric Power Annual 2010 Data Tables*. Accessed May 23, 2010 at http://www.eia.gov/electricity/annual/.

[541] Conventional hydroelectric production was not included because of its baseload nature. The other renewables category does include small, distributed hydroelectricity production.

[542] Pratt RG, PJ Balducci, C Gerkensmeyer, S Katipamula, MCW Kintner-Meyer, TF Sanquist, KP Schneider, and TJ Secrest. 2010. *The Smart Grid: An Estimation of the Energy and $CO_2$ Benefits*. PNNL-19112, Revision 1, Pacific Northwest National Laboratory, Richland, Washington. Accessed May 23, 2012 at http://energyenvironment.pnnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf.

[543] EnerNex Corporation. January 2010. *Eastern Wind Integration and Transmission Study: Executive Summary and Project Overview*. NREL/SR-550-47086, prepared for The National Renewable Energy Laboratory by EnerNex Corporation, Knoxville, Tennessee. Accessed May 30, 2012 at http://www1.eere.energy.gov/wind/pdfs/47086.pdf.

forecasting to transmission system operators, local utilities, and customers.[544] The Bonneville Power Administration forecasts that renewable generation will reach 5,000 megawatts (MW) of wind by 2012 and 9,000 MW by 2017.[545] Without new transmission, large-scale storage, or other smart grid technologies, the added wind capacity could overload circuits.

### A.21.2 Description of Metric and Measurable Elements

The three metrics for grid-connected renewable resources reflect two important aspects of electricity production from renewable resources: the portion of total electricity generated from renewable resources and the amount of $CO_2$ avoided. Metrics 21b and 21c provide a range for the amount of carbon emissions reduced based on less strict and stricter interpretations of smart grid enabling requirements for the integration of renewable resource electricity.

*(Metric 21a): Renewable electricity as a percent of total electricity both in terms of generation and capacity.* The metric is based on the grid-generated other-renewable electricity production and capacity divided by total grid generation and summer capacity. The measure excludes conventional hydroelectricity.

*(Metric 21b): Metric tons of $CO_2$ reduced by renewable energy resources including wind, photovoltaics/solar thermal electric, biomass and small hydroelectric generation.* This measure provides a maximum amount of avoided $CO_2$ emissions due to grid-connected renewable energy using smart grid features.

(*Metric 21c): Percent of grid-connected renewable electricity directly and indirectly resultant from smart grid applications.* The metric reduces the $CO_2$ emissions in Metric 21b to reflect the net benefit of intermittent renewable electricity generation that can be directly attributed to smart grid functions such as the use of regulation and spinning reserves.

### A.21.3 Deployment Trends and Projections

Non-hydro renewable electricity generation climbed from a little over 2 percent of total grid-connected electricity generation in 2005 to more than 4 percent in 2010 (Figure A.78). The increase in renewables generation resulted primarily from new wind generation. Wind generation increased dramatically over the time period from approximately 18 gigawatt-hours (GWh) in 2005 to more than 70 GWh in 2010.[546] Excluding wind, production by other grid-connected renewable electricity sources remained relatively constant (Figure A.79).

Primary causes for the increased amount of renewable energy generation arise from increasing requirements by states for renewable portfolio standards (RPS). The state RPS sets the amount of total generation that must come from renewable resources. Typically, these are set state-by-state with some states having strict timelines with required interim milestones while others have less stringent standards,

[544] Power & Energy. June 2010. *Renewables and the Smart Grid.* Accessed May 30, 2012 at http://www.nextgenpe.com/article/Renewables-and-the-Smart-Grid/.
[545] BPA – Bonneville Power Administration. November 2011. *Forecast of Renewable Projects Connected to BPA Grid Based on Existing Queue and Recent Trends*. Accessed May 30, 2012 at http://transmission.bpa.gov/PlanProj/Wind/documents/Renewable_Forecast_Graph_2017.pdf.
[546] EIA 2011b.

and yet other states have no RPS requirements. Currently, 30 states and the District of Columbia have RPS requirements.[547] Wind is the less costly alternative between wind and solar when incentives are included. In addition, where states mandate a set-aside for solar, the amount is significantly smaller than the overall requirement for renewable energy generation. Without significant state and federal incentives for renewables, the current level of renewables generation would be significantly less. Biomass and geothermal resources are very dependent on the availability of economical and reliable resources for electricity generation.

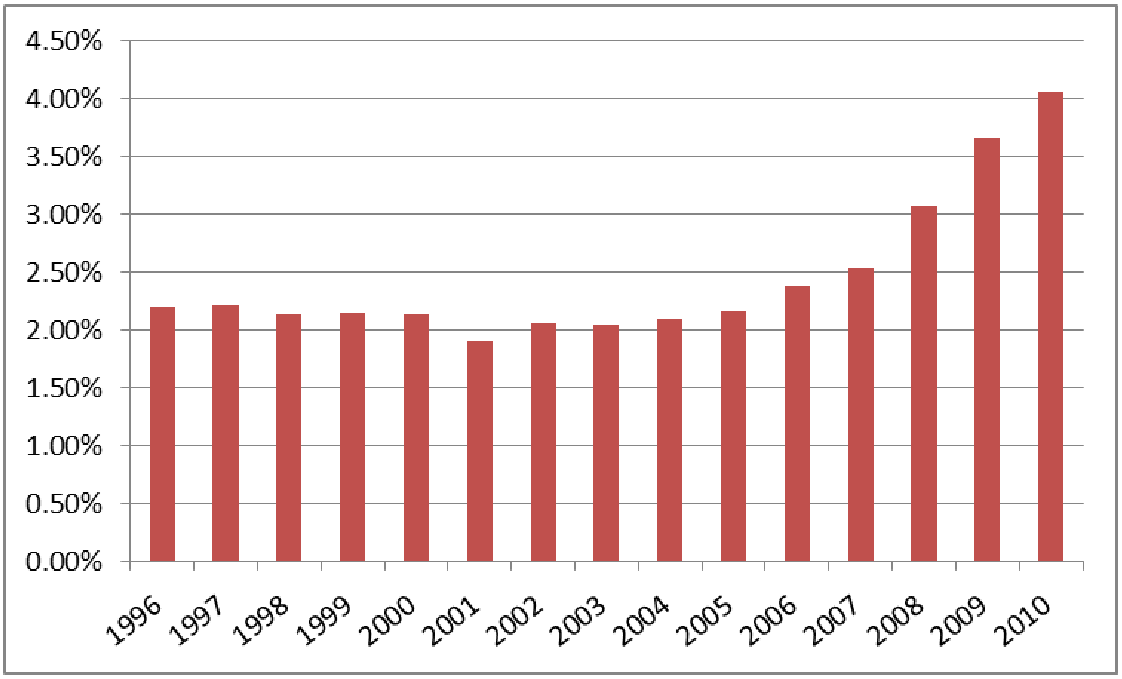



**Figure A.78**. Renewable Generation as a Percentage of Total Generation[548]

Renewable energy capacity as a percentage of total summer peak capacity has grown by almost 150 percent since 2004, increasing from just over 2 percent to more than 5 percent (Figure A.80). While growing, the percentage is relatively small on a national average basis. Wind and solar summer capacity as a percentage of total summer peak capacity indicate the U.S. average penetration for intermittent renewables.

[547] EIA – U.S. Energy Information Agency. January 2012a. *Annual Energy Outlook 2012*. Accessed May 23, 2012 at http://www.eia.gov/forecasts/aeo/er/.
[548] EIA 2011b.

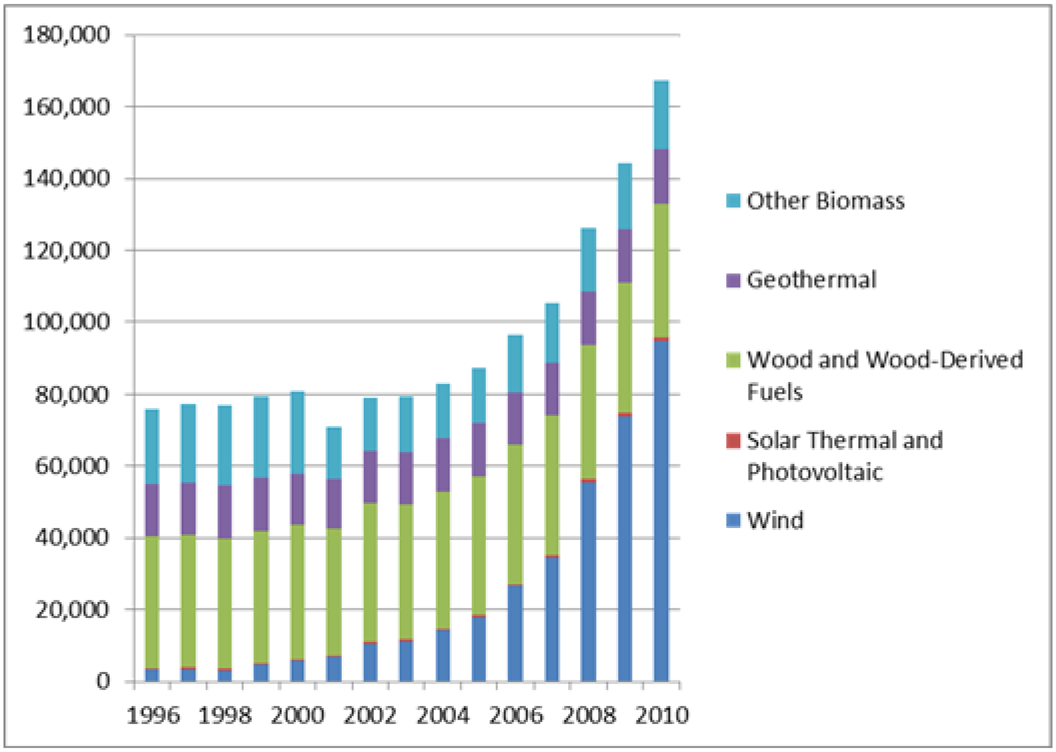



**Figure A.79**. Net Generation by Renewable Energy Resource Type (Thousands of Megawatt-Hours)[549]

[549] EIA – U.S. Energy Information Administration. November 2011c. "Table 2.1.B.: Selected Renewables by Type of Producer." In *Electric Power Annual Data Tables*. Accessed May 23, 2012 at http://www.eia.gov/electricity/annual/.

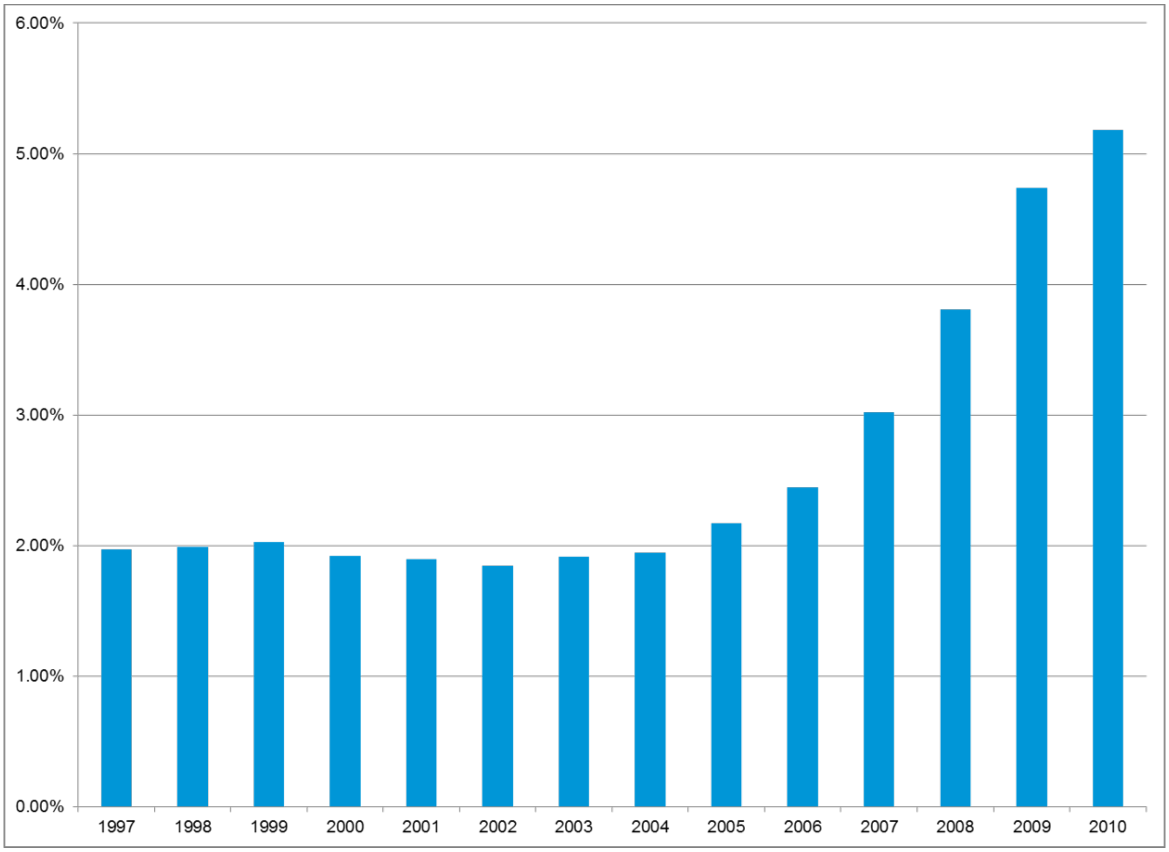



**Figure A.80**. Non-Hydro Renewable Energy Capacity as Percent of Total Summer Peak Capacity[550]

The total electric power sector capacity forecast for intermittent generation is expected to increase nationwide by 91 percent, reaching 6.8 percent of net summer capacity by 2035. Wind will grow by 71 percent while solar thermal and photovoltaics will increase by over 1,000 percent.[551] Renewable-resource electricity output is expected to grow significantly between 2010 and 2035, when total renewables generation excluding conventional hydropower will more than double. Production by renewables will increase more slowly starting in 2026, only growing by approximately 1 percent per year. The main contributors to overall growth are biomass and wind. Municipal solid waste does not contribute significantly to other renewable-resource electricity generation (see Table A.27). In the 2012 AEO Reference Case, renewables account for nearly 39 percent of the increased generation by 2035. The reference case continues to assume that the federal tax credit remains in effect depending on the renewable type. The outlook also assumes that state and federal policies require increased renewable energy as a percent of total production.[552]

[550] EIA 2011c.
[551] EIA – U.S. Energy Information Agency. January 2012b. "Renewable Energy Generating Capacity and Generation, Reference Case." In *Annual Energy Outlook 2012*. Washington, D.C.
[552] EIA 2012b.

**Table A.27**. Actual and Forecast Generation of Renewable Electricity Production 2010 to 2035 (Billions of Kilowatt-Hours)[553]

| Resource | 2010 | 2020 | 2030 | 2035 |
|---|---|---|---|---|
| Wind | 94.5 | 140.6 | 158.7 | 185.8 |
| Wood and Other Biomass | 11.5 | 62.2 | 78.1 | 73.1 |
| Solar Thermal and Photovoltaics | 1.3 | 6.6 | 11.5 | 23.3 |
| Geothermal | 15.7 | 25.0 | 39.9 | 47.4 |
| Biogenic Municipal Waste | 16.6 | 14.7 | 14.7 | 14.7 |
| Offshore Wind | 0.0 | 0.8 | 0.8 | 0.8 |

Avoided wind-power-driven emissions reached almost 95 million metric tons in 2010.[554] Figure A.81 shows the gross benefit of avoided $CO_2$ emissions from grid-connected renewable electricity generation based on the average amount of emissions for non-renewable energy resources.[555]

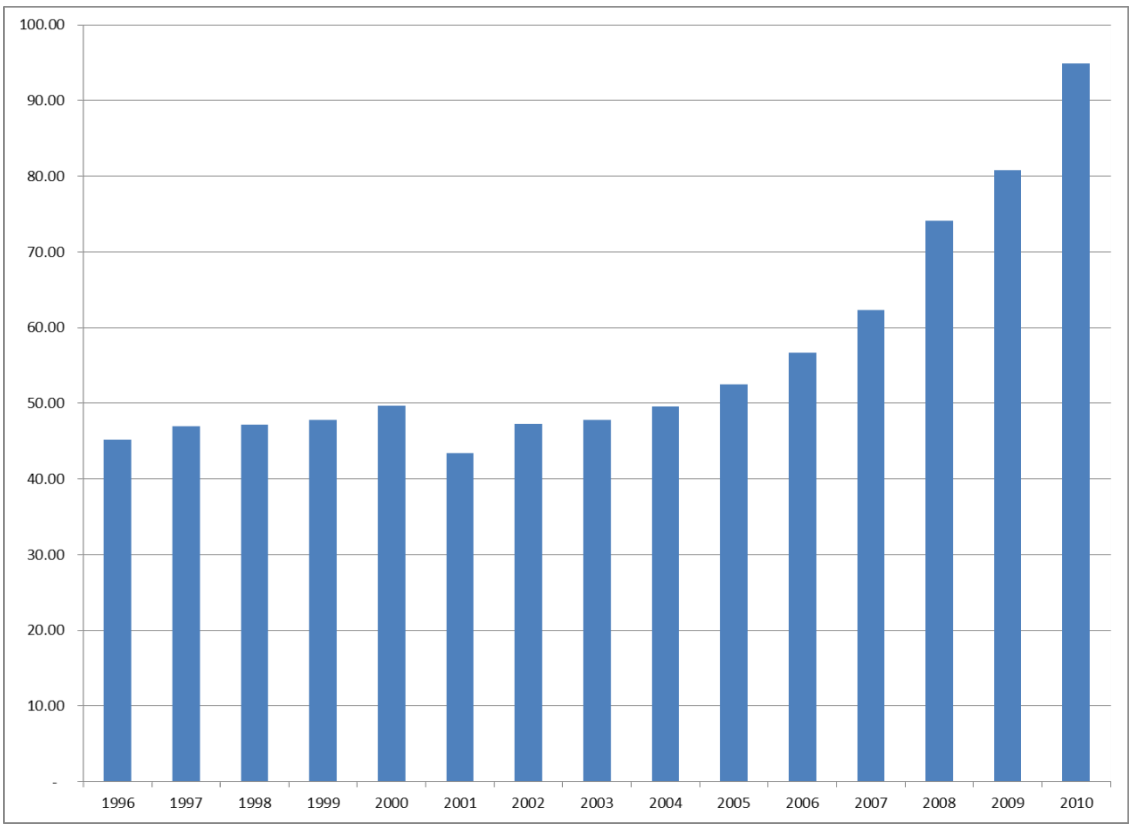



**Figure A.81**. Avoided $CO_2$ Emission by Renewable Energy Electricity Generation (Million Metric Tons $CO_2$)[556]

---

[553] EIA 2012b.
[554] Based on U.S. Energy Information Administration, EIA. 2011d, "Table A.3; Carbon Dioxide Uncontrolled Emission Factors," in *Electric Power Annual 2010.* Accessed May 23, 2012 at http://www.eia.gov/electricity/annual/html/tablea3.cfm and EIA November 2011and EIA 2011a.
[555] The last year of emissions data in this citation was 2008. We assumed the same level of emissions rate for non-renewable energy resources and applied that rate to 2009 and 2010 generation of renewable energy resources.

### A.21.3.1 Associated Stakeholders

Stakeholders include independent renewable power producers, distribution and transmission service providers, balancing authorities, wholesale-electricity traders/brokers/markets, electric-service retailers, reliability coordinators, product and service suppliers, energy policy makers and regulators, standards organizations, the financial community, and end-users (consumers).

- Transmission service providers will need to add significant amounts of transmission lines to effectively transport wind energy from distant production centers to urban population centers.
- Distribution service providers will need to provide net metering opportunities and establish connection standards, advanced voltage control and short-circuit protection schemes at high penetration of renewables.
- Balancing authorities will need the latest in smart grid options to provide them with the ability to balance loads when large amounts of intermittent renewable electricity is a part of the mix. Increasingly, new resources like interruptible load mechanisms and direct load control may be needed. They will need to coordinate transmission of the renewable energy resource between system operators.
- Electric-service retailers will need to balance their distribution loads based on potential distributed generation units within their local grid. In states with renewable portfolio standards, utilities will need to acquire the requisite amounts of renewable energy to meet the requirements.
- Reliability coordinators will need to implement processes and procedures that provide stability and power quality to the grid given the amount of instability large quantities of intermittent renewable energy will cause.
- Policymakers and regulators need to develop the laws and regulations governing interstate transmission. Cooperation between state and federal regulators and investment from the financial community will be required to build the extra-high-voltage (EHV) transmission lines required to deliver electricity from distant production areas.
- Standards organizations will need to write standards that allow interoperability between different equipment types and systems required to integrate the intermittent resources.
- Independent renewable power producers require markets to deliver their renewable electricity. Without adequate prices and demand for renewable electricity, investments will not be undertaken.
- Product and service providers will need to improve renewable energy technologies to make them competitive as the government reduces subsidies. In addition, they will need to develop flexible technologies, including responsive loads, fuel synthesis technologies, storage technologies and generation technologies that can quickly ramp to meet changes in intermittent capacity. Weather forecast service providers will be pressed to find more accurate methods of forecasting weather to improve planning for spinning reserves and regulation.
- The financial community will provide a significant amount of the capital that will be required to implement a smart grid with a significant amount of intermittent renewable energy. Wind and solar power equipment will need to be purchased, and if wind and solar are developed in regions far from

[556] EIA 2011a and 2011d.

demand centers, significant capital will be needed to purchase the transmission lines and infrastructure to integrate the electricity produced.

- End-users will benefit from a decreased carbon footprint in the electricity sector but will pay higher prices for renewable energy. However, as the renewables footprint grows, more price stability will occur as fossil-fuel price volatility will have less impact.

#### A.21.3.2 Regional Influences

The most economic renewable energy resources, such as wind and solar, are located in specific regions. The highest solar potential exists in the desert Southwest while the best wind exists in the West and Midwest. Areas along the Atlantic Coast and in the Southeast have little wind inland and the high level of humidity degrades the solar resource. Figure A.82 indicates the type of renewable energy generation as a percent of total renewable generation by region.

The Pacific West region has the greatest amount of renewable electricity generation (excluding conventional hydrogeneration) as a percent of total generation, followed by the West South Central, West North Central and South Atlantic regions. The Pacific West has the largest percentage of solar and geothermal and third highest wind. The Southwest Central region (which includes Texas) has the largest percentage of wind, followed by the West North Central region. The Pacific West and South Atlantic regions lead in the biomass/biogenic types of renewable resources.[557]

[557] EIA – U.S. Energy Information Agency. 2011e. "Table 1.20: Total Renewable Net Generation by Energy Source and State, 2009." In *Trends in Renewable Energy Consumption and Electricity, 2009*. Accessed May 23, 2012 at http://www.eia.gov/renewable/annual/trends/.

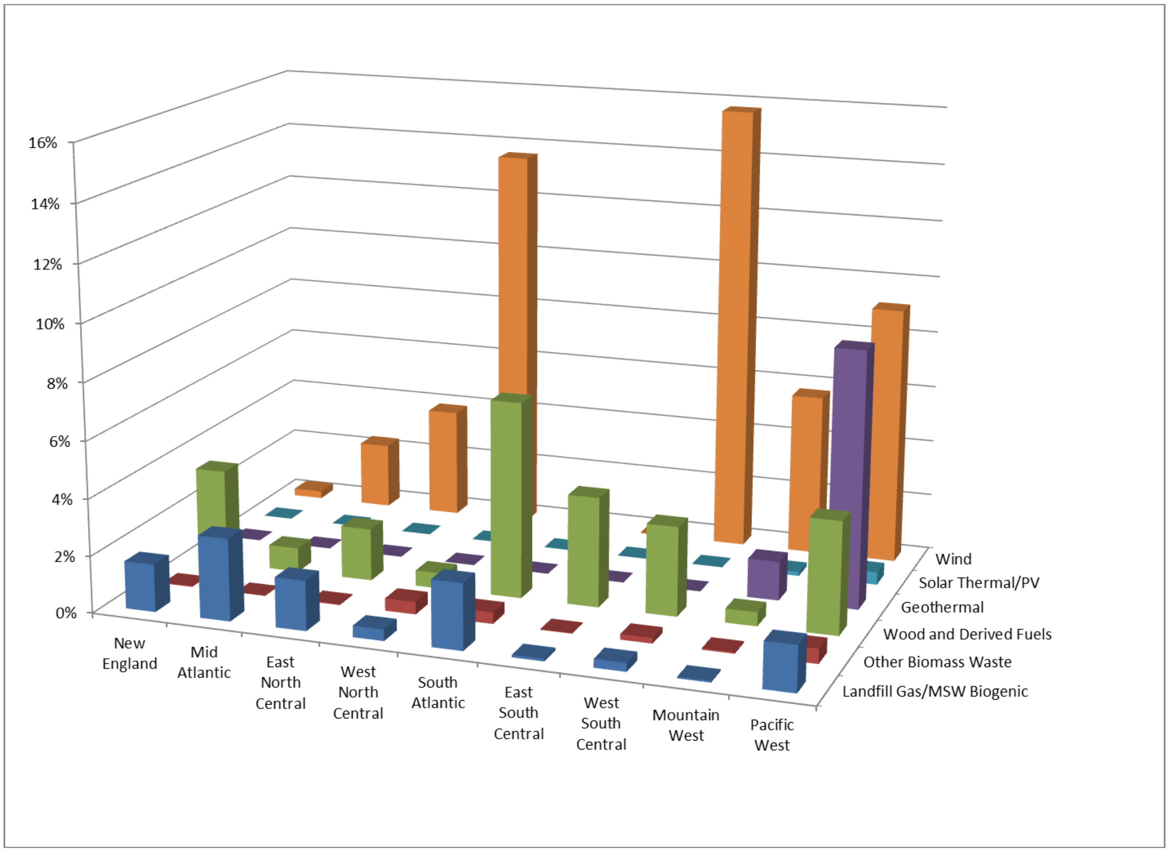



**Figure A.82**. Regional Renewable Generation as Percent of Total Renewable Generation, Percent of Type of Renewable Generation Type, 2009[558]

## A.21.4 Challenges to Deployment

There are a number of technical and business/financial barriers to implementing smart-grid technologies that incorporate renewable electricity generation. These include maintaining grid stability, cost-effective storage technologies, and a relatively high direct cost per installed kilowatt (kW) of capacity for the intermittent sources. The costs of photovoltaics dropped dramatically since the 2010 Smart Grid System Report, but are still high compared with traditional generation methods. These barriers could stall investment in these technologies.

### A.21.4.1 Technical Challenges

Technical barriers include:

- Perhaps the largest technical hurdle for intermittent renewable energy resources to overcome is the impact on grid stability. Wind and solar are not dispatchable (or drawn upon when demand increases above baseload), which provides an additional challenge. Even scale and dispersion will not overcome the variability in production. One particular problem with variability is that where hydroelectric and nuclear base generation exist there can be excess base generation which cannot

[558] EIA 2011e.

easily be ramped down. As such, storage technologies currently under development will need to become cost effective and commercialized.[559,560]

- Another problem to overcome is the variability in frequency and ramp rates. The California independent system operator (CAISO) changed their ramp rates from previously published rates. The new ramp rates include the integration of more than 2,200 MW of solar in addition to almost 6,800 MW of wind by 2012 as a result of the renewable portfolio standard requirement instituted in 2010. The new ramp rates are 30-40 MW per minute higher than the ramp rates in their 2007 report. The load-following up rate requirement is more than 3,700 MW per hour while the load following down rate is nearly 4,000 MW per hour. Currently, intermittent resources are only responsive to generation decrement requests.[561]
- A Bonneville Power Administration study indicated that five classes of technologies are needed to improve integration of intermittent wind production: storage, fuel synthesis, generation, demand response, and operational techniques. Noted among the approaches as providing flexibility, and in some level of development, were capacitors/ultra capacitors; flow batteries/flow-redox batteries such as vanadium, zinc bromine, cerium zinc, and polysulfide; MW-sized batteries; flywheels; hydrogen storage; fuel cells; call rights on plug-in vehicles; and stretching wind prediction time. Most of these technologies/techniques, which are not at the mature stage, were listed as having high capital costs.[562] The emphasis was on providing flexibility to accommodate and balance loads associated with integrating 6,000 MW of wind-generated electricity. Power electronics were also indicated as a technology where the movement to advanced high voltage semiconductors could further reduce cost by increasing round-trip efficiency.[563]
- Inverters may also provide a solution to the high ramp rates required to integrate intermittent renewable resources; inverters can provide reactive power when connecting intermittent resources. Southern California Edison is deploying inverters at the Tehachapi wind farm.[564]
- One technical challenge that needs to be addressed is better wind and cloud prediction models. Better forecasting models, liquid trading hubs and greater granularity in scheduling renewables could reduce some of the ramping issues in maintaining power quality. If utilities managed electricity in 15- to 30-minute-ahead increments rather than in one-hour-ahead increments, some of the intermittency problem could be reduced.[565]
- Wind faces some environmental challenges in that neighbors complain about noise, lighting effects and visual pollution.

---

[559] AEA – Aegent Energy Advisors Inc. March 2012. *Renewable Energy Integration and Wind Challenges*. Accessed May 30, 2012 at http://www.aegent.ca/newsletters/20120320_3.html.

[560] CAISO – California Independent System Operator. August 2010. *Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS*. Accessed May 30, 2012 at http://www.caiso.com/2804/2804d036401f0.pdf.

[561] CAISO August 2010.

[562] BPA/NWPCC – Bonneville Power Administration and the Northwest Power and Conservation Council. March 2007. *Northwest Wind Integration Action Plan.* WIF document 2007-01. Accessed May 30, 2012 at http://www.uwig.org/nwwindintegrationactionplanfinal.pdf.

[563] Johnson, M, D Danielson, I Gyuk 2010. "Grid Scale Energy Storage." Presentation at ARPE-E Pre-Summit Workshop. Washington, D.C.

[564] Campbell C. June 2011. *Renewable Integration: Solving the Volatility of a Smart Grid*. Renewable Energy World.com. Accessed May 30, 2008 at http://www.renewableenergyworld.com/rea/news/article/2011/06/renewable-integration-solving-the-volatility-of-a-smart-grid.

[565] The Daily Energy Report. January 2011. *Integrating Renewable Resources onto the Grid*. Accessed May 30, 2012 at http://www.dailyenergyreport.com/2011/01/integrating-renewable-resources-onto-the-grid/.

### A.21.4.2 Business and Financial Challenges

Business and financial barriers include:

- Some renewable energy resources are considerably more expensive than coal-fired or natural-gas-fired electricity generation facilities. By 2017, EIA expects levelized costs for wind to be approximately 50 percent greater than for natural-gas-fired combined-cycle turbines, but that costs will be close to similar when carbon sequestration is included, according to EIA's July 2012 report. Large PV will only cost approximately 70 percent more than natural gas with carbon sequestration by 2017. If investment tax credits and production tax credits are extended the differences will be less.[566] Renewable portfolio standards and the associated renewable energy credits help offset the higher cost renewables.
- Wind resources will potentially require significantly more transmission lines to bring electricity from good resource areas to the grid. Wind is typically found in less populated areas where fewer transmission lines exist. A study on the Eastern Interconnection indicated that between $65 billion and $93 billion (2009 dollars) would be required in transmission capacity funding, depending on the scenario.[567]
- CAISO drafted a business approach to solving the intermittent generation problem by developing a market for a flexible ramping product. The value of the flexible ramping product is based on the system variability and uncertainty between the real time pre-dispatch process and the real-time dispatch. The flexible product begins 5 hours ahead and progresses on 15-minute intervals until 5 minutes ahead when actual economic dispatches occur. The approach is a draft document.[568] In an earlier paper they laid out a roadmap of options on how they would set up the California energy market to handle the integration of renewables, including the flexible product approach, regulation services, real-time imbalance service, and operating reserves.[569]
- Most of the technologies/techniques required to make the grid system more flexible are characterized as immature technologies and are listed as having high capital costs.[570]

## A.21.5 Metric Recommendations

A clearer definition of what is attributable to the smart grid is needed in order to more accurately attribute reduced emissions to renewable energy generation for Metric 21.c. Currently, different studies apply different values to the amount of renewable energy transmission that is supported by smart grid functions. Some authors argue that all renewables generation is based on some smart grid application to integrate the electricity. For example, they argue that without synchrophasors and direct load controls, integration of intermittent generation would cause system failure more often than it does now. On the other hand, others argue these technologies are not new, and therefore are not a smart grid application. There is at least one recommendation that metric 21.c should be removed.

[566] EIA – U.S. Energy Information Administration. July 2012c. "Levelized Cost of New Generation Resources in Annual Energy Outlook 2012." In AEO2012 DOE/EIA-0393(2012). Accessed November 11, 2013 at http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

[567] EnerNex Corporation January 2010.

[568] Xu L and D Tretheway. April 2012. *Flexible Ramping Products: Draft Final Proposal*. California Independent System Operator. Accessed May 30, 2012 at http://www.caiso.com/Documents/DraftFinalProposal-FlexibleRampingProduct.pdf.

[569] CAISO – California Independent System Operator. July 2011. *Renewables Integration Market Vision & Roadmap: Day of Market – Initial Straw Proposal*. Accessed May 30, 2012 at http://www.caiso.com/2bb3/2bb3e594394f0.pdf.

[570] BPA/NWPCC 2007.

# Appendix B

# Electricity Service Provider Interviews

# Appendix B
# Summary of Electricity Service Provider Interviews

## B.1 Background Concerning the Interviews

To assess the state of smart-grid deployment, metrics were established to measure attributes of interest. Data collection for the Smart Grid Status and Metrics Report was performed by interviewing 30 selected electricity service providers representing a cross section of the industry. As part of the agreement with interviewees, the results were provided to all participants in a blinded form in advance of making this report public.

As the interviews only involved electricity service providers, they emphasized aspects of the electric utility enterprise. Other aspects, particularly those of deployment advances on the demand side, were beyond the scope of the interviews.

## B.2 Approach

APQC, a productivity-benchmarking and best-practice research firm, was contracted to develop the interview questionnaire. The interview approach followed a four-step benchmarking methodology: plan, collect, analyze and report.

### B.2.1 Plan

Planning of the interview approach was a joint effort of the interview team with the following tasks:

- Develop an understanding of project-critical success factors and time constraints.
- Prepare the interview tool (i.e., assessment and interview guides).
- Select types of representative organizations to target for data collection.
- Update metrics and indicators to be collected and reported.

### B.2.2 Data Collection

Data collection included 30 electricity service providers within the United States representing a broad demographic (e.g., coast to coast; small to large; public, private and co-op) and included the following tasks:

- securing commitment from participating organizations
- collecting quantitative and qualitative data from participating organizations.

### B.2.3 Data Validation and Analysis

Data validation and normalization were performed as necessary, along with high-level analysis, to ensure the highest quality and accuracy in comparison. Both blinded raw data and aggregated analysis are provided in this report.

### B.2.4 Final Report

This report is the final part of the study project, providing a summary of the study itself to augment the data deliverables mentioned above:

- a list of participating organizations
- data results
- partner profiles
- findings.

## B.3 Metrics

Along with the principal characteristics of a smart grid, the interview team aligned the metrics with the Smart Grid Maturity Model (SGMM) administered by Carnegie Mellon University's Software Engineering Institute. This model establishes a roadmap for a smart grid within an electricity service provider at five levels of maturity. It is used to evaluate an electricity service provider's current state and map future initiatives. The SGMM evaluates each electricity service provider against key characteristics in eight domains:

- Strategy, Management & Regulatory
- Organization & Structure
- Grid Operations
- Work & Asset Management
- Technology
- Customer
- Value Chain Integration
- Societal & Environmental.

The resulting interview questionnaire used to collect the data as part of this study can be found in Section B.7.

## B.4 Study Partners

The 30 companies that contributed data to this study are listed in Table B.1.

**Table B.1**. Interview Participants

| Company | Size (Customers) | Region | Type | Ownership |
|---|---|---|---|---|
| Burbank Water and Power | 52,100 | California | T&D, Gen | Municipal |
| CenterPoint Energy | 2,164,509 | Texas | T&D | Investor Owned |
| City of Columbus, DOPW-Power | 12,500 | Ohio | D | Municipal |
| City of Hamilton | 29,014 | Ohio | T&D, Gen | Municipal |
| City of Piqua Power System | 10,551 | Ohio | D, Gen | Municipal |
| City of Wapakoneta | 5,327 | Ohio | T | Municipal |
| City of Westerville Electric Division | 16,015 | Ohio | T&D | Municipal |
| Coldwater Board of Public Utilities | 6,594 | Michigan | T&D, Gen | Municipal |
| ComEd | 3,700,000 | Illinois | T&D | Investor Owned |
| Georgia Power Company | 2,351,812 | Georgia | T&D, Gen | Investor Owned |
| Glendale Water and Power | 84,881 | California | T&D, Gen | Municipal |
| Jersey Central Power and Light | 1,097,438 | New Jersey | T&D | Investor Owned |
| Met-Ed | 552,021 | Pennsylvania | T&D | Investor Owned |
| Mon Power | 386,654 | West Virginia | T&D | Investor Owned |
| Ohio Edison | 1,032,484 | Ohio | T&D | Investor Owned |
| Penelec | 588,817 | Pennsylvania | T&D | Investor Owned |
| Penn Power | 160,164 | Pennsylvania | T&D | Investor Owned |
| Pepco | 791,946 | Maryland, DC | T&D | Investor Owned |
| Portland General Electric | 822,927 | Oregon | T&D, Gen | Investor Owned |
| Potomac Edison | 388,146 | Maryland | T&D | Investor Owned |
| PPL Electric Utilities | 1,369,821 | Pennsylvania | T&D, Gen | Investor Owned |
| Progress Energy Carolinas | 1,445,158 | North Carolina | T&D, Gen | Investor Owned |
| Salt River Project | 953,848 | Arizona | T&D, Gen | State |
| San Diego Gas and Electric | 1,395,113 | California | T&D, Gen | Investor Owned |
| Southern California Edison Co. | 4,860,275 | California | T&D | Investor Owned |
| Toledo Edison | 308,011 | Ohio | T&D | Investor Owned |
| Tucson Electric Power | 409,202 | Arizona | T&D, Gen | Investor Owned |
| Wadsworth Electric and Communications | 12,825 | Ohio | T&D, Gen | Municipal |
| West Penn Power | 717,714 | Pensylvania | T&D | Investor Owned |

These companies represent the breadth of the United States with about 18 percent of U.S. customers represented, as shown in Figure B.1. Approximately 26.5 million customers are served by these utilities. In addition, these companies provide a balanced view of both regulated and deregulated electricity service providers, as shown in Figure B.2.

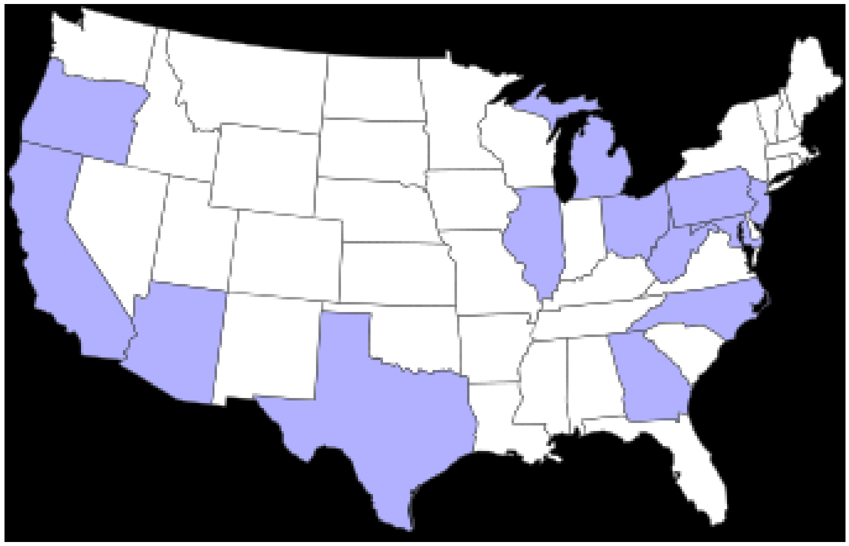


**Figure B.1**. Coverage of the United States by Participating Organizations

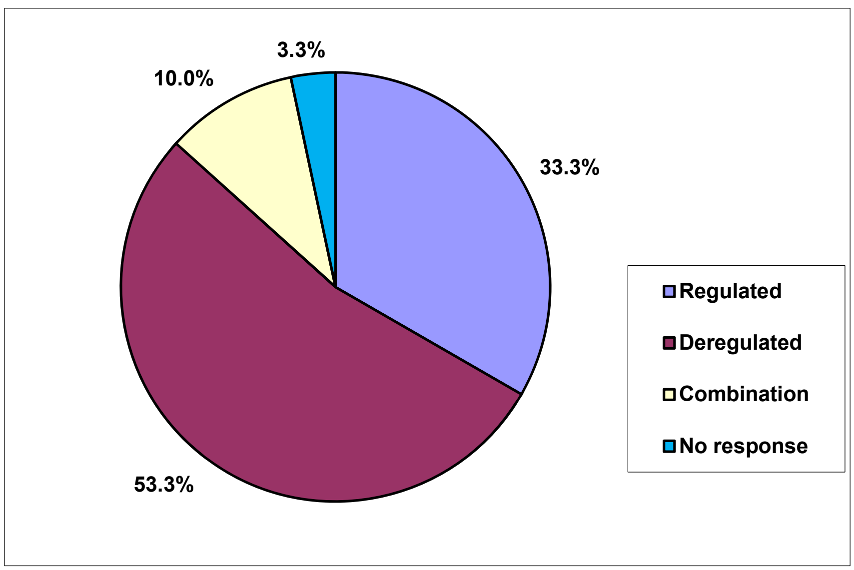



**Figure B.2**. Market Conditions of Participating Organizations

## B.5 Findings

The major insight gained from the data collection efforts is that deployment of smart-grid capabilities among US electric electricity service providers is in its early stages. While in most smart grid areas progress is limited, there are many areas (e.g., advanced metering infrastructure, demand response, smart grid investment recovery) where significant gains are being made. Some of the key observations are provided here:

- Fewer than half (37%) of electricity service providers reported that distributed intelligence and analytics (e.g., statistics, computer programming, and operations research) are now available across functions and systems.
- Most electricity service providers (70%) have a demand response program.

- Half of electricity service providers reported an interoperability maturity level in the Smart Grid Interoperability Maturity Model of Level 3 or higher.
- Deployment of advanced meters has increased significantly since 2010 for all customer groups (see Table B.2).
- Time-based rate plans have limited penetration across the respondents:
  - Only one organization had appreciable residential participation for critical peak pricing at 58% of customers; other organizations averaged less than 2% of customers participating.
  - Only one organization had appreciable residential participation for time-of-use pricing at 27% of customers; one other organization was at 8% and all others below 2%.
  - Real-time pricing was reported by only two utilities, primarily for industrial customers.
  - Time-of-use pricing was the most prevalent, with numerous utilities reporting it in place for 100% of their industrial customers.
- While many organizations reported supervisory control and data acquisition (SCADA) points within their substations, only one utility out of ten reported an appreciable amount that was shared across their enterprise.
- Only three organizations reported that phasor measurement unit (PMU) measurements points are shared multilaterally, each at 100%.
- No organizations reported an appreciable amount of load served by automated circuits; for those reporting low values, those may be proof-of-concept efforts.
- No organization had more than 2% of customers participating in net metering programs.

**Table B.2**. Deployment of Advanced Meters

| Metric Name | 2010 | | | | 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Top Performers | Median | Bottom Performers | Count | Top Performers | Median | Bottom Performers | Count |
| Advanced metering infrastructure (residential) as a % of total meters (residential) | 69.9% | 3.4% | 0.1% | 20 | 99.5% | 81.0% | 0.0% | 16 |
| Advanced metering infrastructure (commercial) as a % of total meters (commercial) | 28.4% | 2.3% | 0.1% | 7 | 96.8% | 82.9% | 10.0% | 17 |
| Advanced metering infrastructure (industrial) as a % of total meters (industrial) | 100.0% | 17.4% | 0.0% | 7 | 100.0% | 15.4% | 0.0% | 16 |
| Advanced metering infrastructure (total) as a % of total meters (total) | 69.9% | 3.6% | 0.1% | 20 | 99.0% | 83.1% | 1.6% | 15 |

There are areas in which electricity service providers have not moved rapidly; these are automated response to pricing signals for major energy devices within a premise and automated response to frequency signals for energy-using devices within a premise.  Of the electricity service providers interviewed for this report, none have fully operationalized these features. However, 23.3% and 13% have automated response to pricing signals and automated response to frequency signals in development, respectively (see Figures B.3 and B.4).

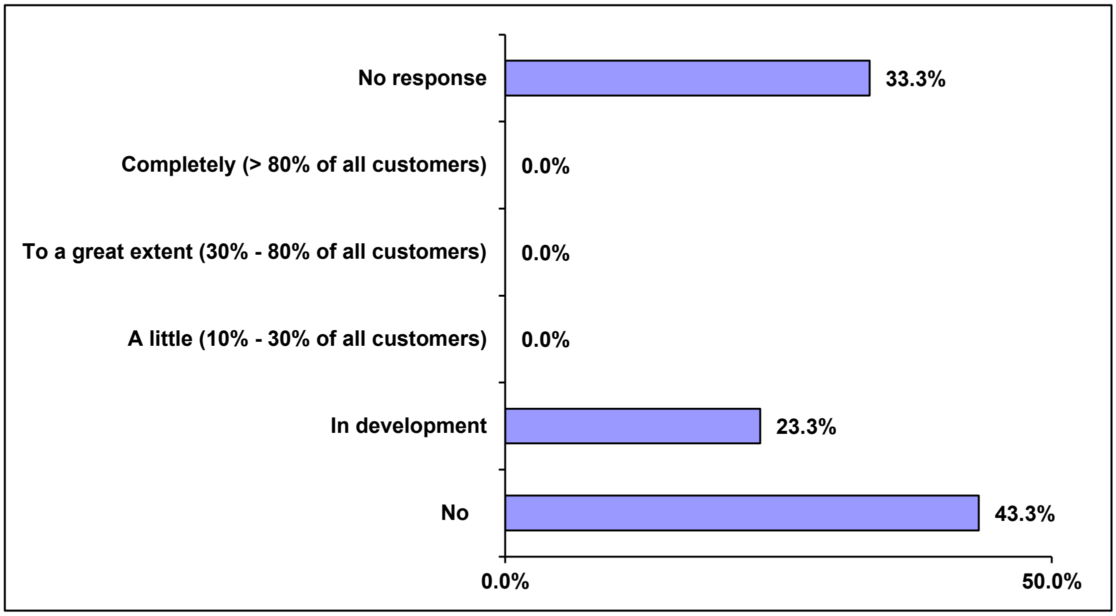



**Figure B.3**. Automated Response to Pricing Signals

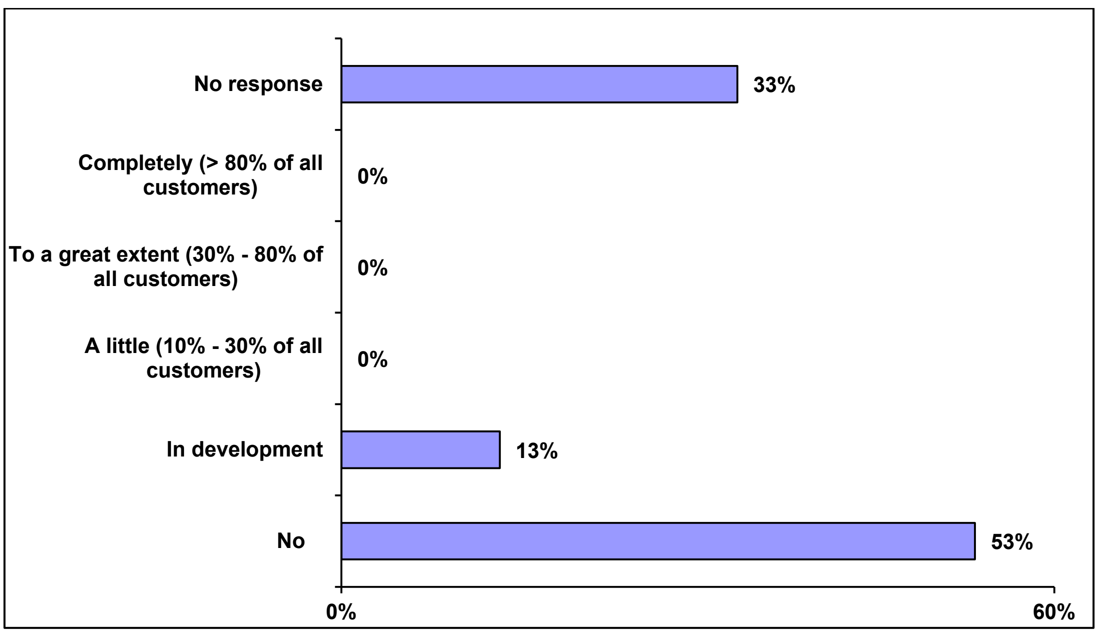



**Figure B.4**. Automated Response to Frequency Signals

In Figures B.5 through B.8 below, performance benchmarks are reported in quartiles. The top-performer benchmark is the first quartile ($25^{th}$ percentile), the bottom-performer benchmark is the fourth quartile ($75^{th}$ percentile), and the median is the $50^{th}$ percentile.

In this report, the top-performer benchmark represents the level below which 75 percent of all responses fall in terms of performance. Conversely, the bottom-performer benchmark reflects the level below which 25 percent of all responses fall in terms of performance. The median reflects the metric below and above which there is an equal number of values. The N value reflects the sample size based on the number of participants.

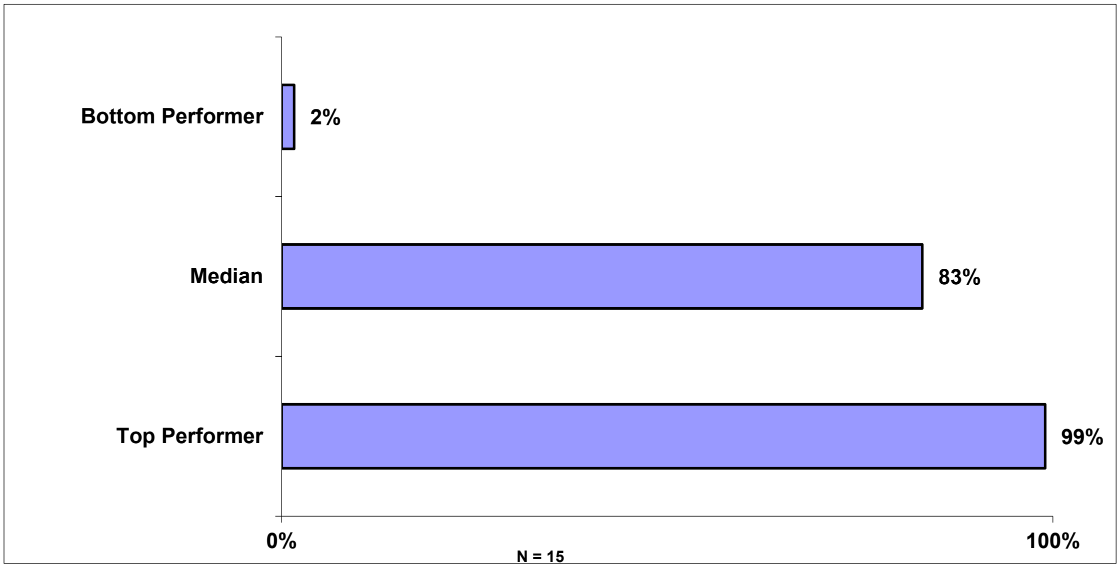



**Figure B.5**. Advanced Metering Infrastructure as a Percentage of Total Meters

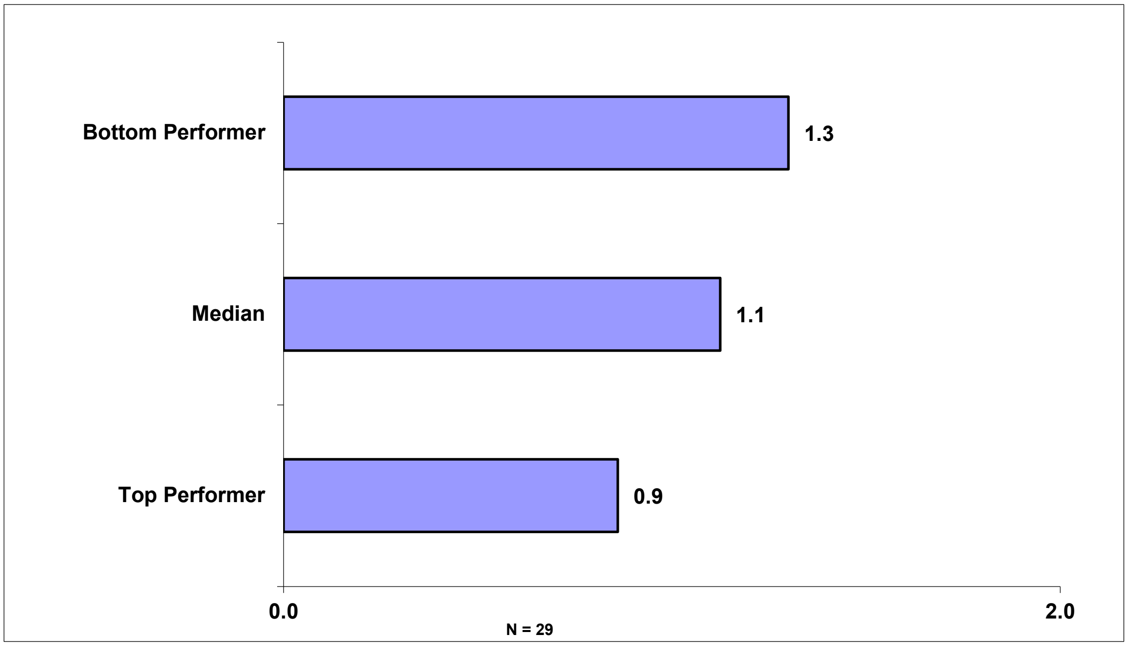



**Figure B.6**. Actual SAIFI

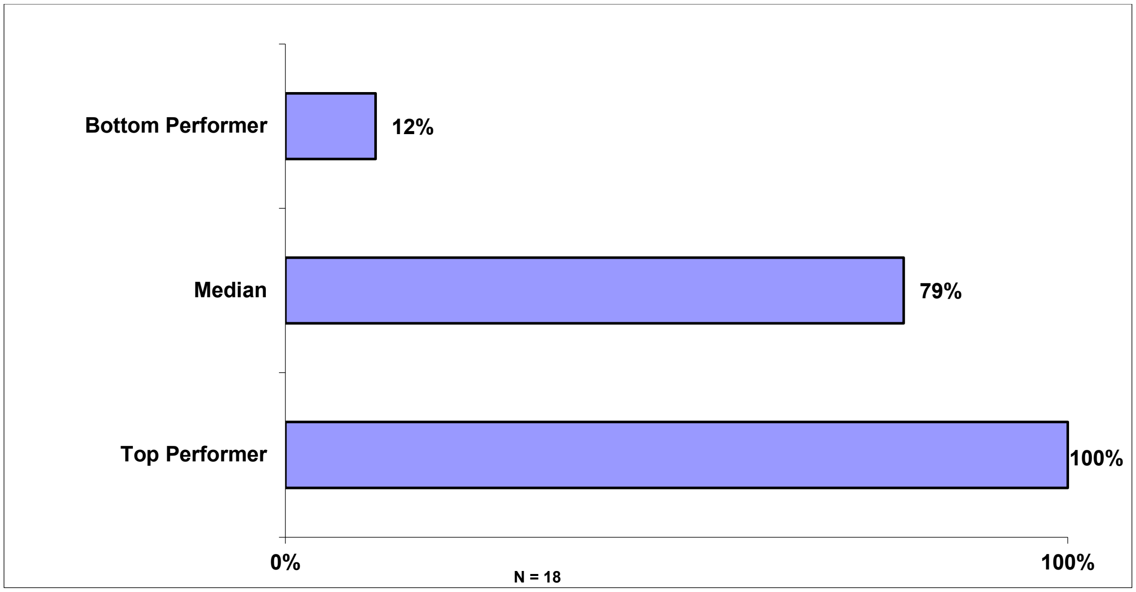



**Figure B.7**. Percentage of Substations That Are Automated

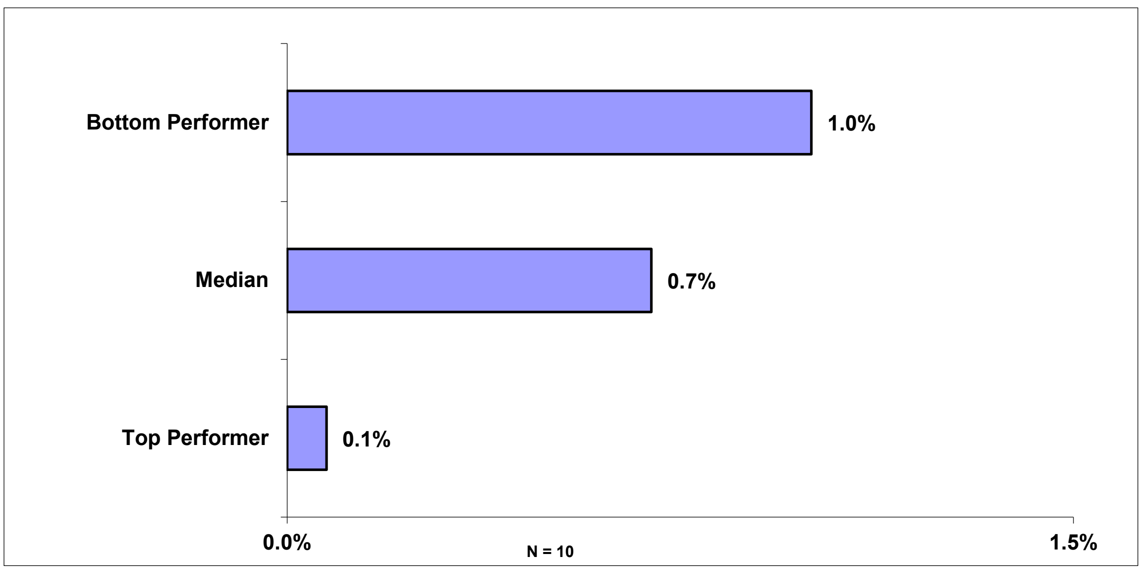



**Figure B.8**. Percentage of Residential Customer Complaints Related to Power Quality Issues (Excluding Outages)

The full set of results and analysis from the study are provided in sections that follow. The aggregated responses to both quantitative and qualitative questions are presented.

### B.5.1 Interview Results

#### B.5.1.1 Key Terms

- N: The N value reflects the sample size of a distribution.
- Bottom Performer: the benchmark represents the performance level below which 25 percent of all responses fall (i.e., 25$^{th}$ percentile).
- Median: the median performance level for all participants in the database. The median reflects the level below and above which there is an equal number of values.
- Top Performer: the benchmark represents the level below which 75 percent of all responses fall in terms of performance.
- NA: information is not available.
- Average: the arithmetic mean.
- Weighted average: the calculated value based on a weighting element. Calculation is made by taking a respondent's percentage of total as a weighting element and multiplying that percentage times the company's metric value. The weighted average is the sum of data from all participants that had a metric value.
- All-participants peer group: reflects all business entities that provided data.

Note: Results in this report are drawn from relatively small sample sizes. Care should be exercised when applying these results to a larger population.

#### B.5.1.2 Scope

Interviews pertained to the following deployment attributes associated with transmission and distribution network and generation operations:

- information technology penetration
- communications network capabilities
- costs
- obstacles.

#### B.5.1.3 Quantitative and Qualitative Data Summary

Data in Table B.3 and Table B.4 originated from transmission-and-distribution and generation operations.

**Table B.3**. Summary of Quantitative Data

| Formula | Metric Name | Average | Weighted Average | Weighting Element | Top Performers | Median | Bottom Performers | Count |
|---|---|---|---|---|---|---|---|---|
| Survey Question | Key Performance Indicators | | | | | | | |
| 2a | Percentage of automated substations | 60.9% | 85.7% | Total Substations | 100.0% | 79.0% | 11.5% | 18 |
| 2b | Percentage of substations with outage detection | 68.0% | 93.0% | Total Substations | 100.0% | 90.0% | 39.5% | 19 |
| 2c | Percentage of circuits with outage detection | 69.2% | 93.6% | Total Customers | 100.0% | 92.5% | 45.0% | 20 |
| 2d | Percentage of intelligent electronic devices (IEDs) with communications on grid | 47.7% | 80.4% | Total Customers | 100.0% | 25.0% | 2.5% | 15 |
| 2e | Percentage of relays that are electromechanical | 50.1% | 58.4% | Total Customers | 70.0% | 60.0% | 35.0% | 17 |
| 2f | Percentage of relays that are microprocessor | 41.9% | 41.5% | Total Customers | 50.0% | 36.0% | 30.0% | 17 |
| 2i.i | Average customer load (kW) (residential) | 1.5 | 1.4 | Residential Customers | 1.5 | 1.2 | 0.9 | 21 |
| 2i.ii | Average customer load (kW) (commercial) | 12.7 | 7.9 | Commercial Customers | 10.1 | 2.0 | 0.9 | 20 |
| 2i.iii | Average customer load (kW) (industrial) | 956.8 | 640.4 | Industrial Customers | 550.6 | 26.0 | 8.9 | 21 |
| 2j.i.1/2j.i.2 | Advanced metering infrastructure (residential) as a % of total meters (residential) | 59.1% | 85.5% | Residential Meters | 99.5% | 81.0% | 0.0% | 16 |
| 2j.ii.1/2j.ii.2 | Advanced metering infrastructure (commercial) as a % of total meters (commercial) | 57.0% | 72.7% | Commercial Meters | 96.8% | 82.9% | 10.0% | 17 |
| 2j.iii.1/2j.iii.2 | Advanced metering infrastructure (industrial) as a % of total meters (industrial) | 44.5% | 65.8% | Industrial Meters | 100.0% | 15.4% | 0.0% | 16 |
| (2j.i.1+2j.ii.1+2j.iii.1) / (2j.i.2+2j.ii.2+2j.iii.2) | Advanced metering infrastructure (total) as a % of total meters (total) | 60.3% | 86.5% | Total Meters | 99.0% | 83.1% | 1.6% | 15 |
| 13 | Energy storage capacity as a % of total capacity on grid (batteries, flywheels, thermal, pumped hydro) | 2.9% | 1.3% | Total Customers | 1.00% | 0.00% | 0.00% | 17 |
| 14 | Non-dispatchable, non-controllable renewable generation as a % of total capacity on grid | 12.4% | 8.6% | Total Customers | 17.2% | 5.0% | 3.0% | 13 |
| 17.a | Predicted SAIFI | 1.2 | 1.2 | Total Customers | 1.0 | 1.2 | 1.4 | 18 |

**Table B.3.** (contd)

| Formula | Metric Name | Average | Weighted Average | Weighting Element | Top Performers | Median | Bottom Performers | Count |
|---|---|---|---|---|---|---|---|---|
| 17.b | Actual SAIFI | 1.1 | 1.1 | Total Customers | 1.0 | 1.2 | 1.4 | 18 |
| 17.c | Predicted SAIDI | 117.8 | 126.4 | Total Customers | 0.9 | 1.1 | 1.3 | 29 |
| 17.d | Actual SAIDI | 105.1 | 120.2 | Total Customers | 53.8 | 131.4 | 171.0 | 15 |
| 17.e | Predicted MAIFI | NA | NA | Total Customers | 49.3 | 94.2 | 153.3 | 26 |
| 17.f | Actual MAIFI | 2.7 | 2.8 | Total Customers | 0.8 | 1.7 | 3.9 | 11 |
| 19.b/2.m | Percentage of lines with dynamic rating | NA | NA | Total Customers | NA | NA | NA | 1 |
| 19.c | Average transmission transfer capacity expansion due to use of dynamic rather than fixed transmission line ratings | NA | NA | Total Customers | NA | NA | NA | 1 |
| 21.a | Percentage of residential customer complaints related to power quality issues (excluding outages) | 1.0% | 1.2% | Residential Customers | 0.1% | 0.7% | 1.0% | 10 |
| 21.b | Percentage of commercial customer complaints related to power quality issues (excluding outages) | 0.9% | 0.4% | Commercial Customers | 0.0% | 0.1% | 2.0% | 9 |
| 21.c | Percentage of industrial customer complaints related to power quality issues (excluding outages) | 1.7% | 0.1% | Industrial Customers | 0.0% | 0.0% | 2.0% | 9 |
| (5.a.i / 2h.i)*1000 | Customers enrolled in time-based critical peak pricing (CPP) program per 1000 customers (residential) | 31.24 | 39.19 | Residential Customers | 0.00 | 0.00 | 0.00 | 19 |
| (5.a.ii / 2h.ii)*1000 | Customers enrolled in time-based CPP program per 1000 customers (commercial) | 121.50 | 90.77 | Commercial Customers | 5.19 | 0.00 | 0.00 | 8 |
| (5.a.iii / 2h.iii)*1000 | Customers enrolled in time-based CPP program per 1000 customers (industrial) | 3.20 | 40.53 | Industrial Customers | 21.24 | 0.00 | 0.00 | 7 |
| (5.b.i / 2h.i)*1000 | Customers enrolled in time-based real time pricing (RTP) program per 1000 customers (residential) | 0.00 | 0.00 | Residential Customers | 0.00 | 0.00 | 0.00 | 7 |
| (5.b.ii / 2h.ii)*1000 | Customers enrolled in time-based RTP program per 1000 customers (commercial) | 0.68 | 1.37 | Commercial Customers | 0.10 | 0.00 | 0.00 | 7 |
| (5.b.ii / 2h.iii)*1000 | Customers enrolled in time-based RTP program per 1000 customers (industrial) | 16.88 | 34.00 | Industrial Customers | 9.63 | 3.74 | 0.00 | 6 |
| (5.c.i / 2h.i)*1000 | Customers enrolled in time-based time of use (TOU) program per 1000 customers (residential) | 25.55 | 26.71 | Residential Customers | 8.29 | 2.56 | 0.14 | 16 |
| (5.c.ii / 2h.ii)*1000 | Customers enrolled in time-based TOU program per 1000 customers (commercial) | 52.08 | 45.62 | Commercial Customers | 101.24 | 28.40 | 1.29 | 13 |
| (5.c.iii / 2h.iii)*1000 | Customers enrolled in time-based TOU program per 1000 customers (industrial) | 368.66 | 247.53 | Industrial Customers | 968.15 | 79.80 | 13.18 | 12 |

**Table B.3.** (contd)

| Formula | Metric Name | Average | Weighted Average | Weighting Element | Top Performers | Median | Bottom Performers | Count |
|---|---|---|---|---|---|---|---|---|
| 7.a | SCADA points per substation | 303.4 | 431.2 | Total Substations | 431.0 | 148.0 | 98.0 | 15 |
| 7.b | Total SCADA points shared per substation (ratio) | 2.4 | 18.4 | Total Substations | 0.71 | 0.02 | 0.00 | 10 |
| 7.c | Percentage of transmission-level PMU measurement points shared multi-laterally | 21.4% | 67.0% | Total Customers | 0.000% | 0.000% | 0.000% | 14 |
| 9.b | Percentage of your smart grid investment to date that has been explicitly recovered through the rate case | 57.6% | 59.8% | Total Customers | 100.0% | 80.0% | 0.0% | 23 |
| 9.d | Percentage of your future smart grid investment you expect to recover through rate recovery | 84.2% | 94.9% | Total Customers | 100.0% | 100.0% | 100.0% | 26 |
| 11.a / (2h.i+2h.ii+2h.iii) | Percentage of customers served by automated circuits | 4.7% | 21.0% | Total Customers | 0.7% | 0.0% | 0.0% | 17 |
| 11.b / 2k.i | Percentage of load served by automated circuits | 0.1% | 0.1% | Total Customers | 0.0% | 0.0% | 0.0% | 14 |
| 12.a / (2h.i+2h.ii+2h.iii) | Percentage of customers that are participating in net metering programs | 0.4% | 0.4% | Total Customers | 0.4% | 0.2% | 0.0% | 16 |
| 12.b / 12.c | Percentage of kW capacity of residential distributed generation involved in net metering programs | 0.4% | 0.4% | Residential Customers | 0.3% | 0.1% | 0.1% | 8 |
| 18.a | Yearly average capacity factor for a typical mile of transmission line (%) | 38.2% | NA | NA | 47.5% | 37.5% | 27.5% | 6 |
| 18.a | Average peak capacity factor for a typical mile of transmission line (%) | NA | NA | NA | NA | NA | NA | 2 |
| 18.b | Yearly average peak capacity factor per mile of transmission line (%) | 44.0% | NA | NA | 47.5% | 37.5% | 27.5% | 6 |
| 18.b | Average peak capacity factor per mile of transmission line (%) | NA | NA | NA | NA | NA | NA | 3 |
| 18.c | Yearly average peak distribution-transformer capacity factor (%) | 39.9% | 42.6% | Total Customers | 53.1% | 31.7% | 30.3% | 6 |
| 18.c | Average peak distribution-transformer capacity factor (%) | NA | NA | Total Customers | NA | 74.0% | NA | 4 |
| | Supporting Indicators | | | | | | | |
| 24.i/ (2h.i+2h.ii+2h.iii) | Residential distribution customers as a % of total distribution customers | 87.0% | 88.0% | Residential Customers | NA | NA | NA | 28 |
| 24.ii/ (2h.i+2h.ii+2h.iii) | Commercial distribution customers as a % of total distribution customers | 12.5% | 11.9% | Commercial Customers | NA | NA | NA | 28 |
| 24.iii/ (2h.i+2h.ii+2h.iii) | Industrial distribution customers as a % of total distribution customers | 0.5% | 0.8% | Industrial Customers | NA | NA | NA | 28 |
| 21 / ((2h.i+2h.ii+2h.iii) / 1000) | Size of Service Territory in square miles per 1000 customers | 7.4 | 8.5 | Total Customers | NA | NA | NA | 26 |
| 2.n.i / (2.n.i+2.n.ii+2.n.iii) | < 13 kV substations as a % of total substations | 41.0% | 60.7% | Total Substations | NA | NA | NA | 24 |

**Table B.3.** (contd)

| Formula | Metric Name | Average | Weighted Average | Weighting Element | Top Performers | Median | Bottom Performers | Count |
|---|---|---|---|---|---|---|---|---|
| 2.n.ii / (2.n.i+2.n.ii+2.n.iii) | >= 13 kV < 35 kV substations as a % of total substations | 28.2% | 20.6% | Total Substations | NA | NA | NA | 24 |
| 2.n.iii / (2.n.i+2.n.ii+2.n.iii) | >= 35 kV substations as a % of total substations | 30.8% | 18.8% | Total Substations | NA | NA | NA | 24 |
| | Demographics | | | | | | | |
| 2.g | Number of employees | 1,863 | NA | NA | NA | NA | NA | 27 |
| 2h.i+2h.ii+2h.iii | Total customer count | 786,238 | NA | NA | NA | NA | NA | 29 |
| | Megawatts: | | | | | | | |
| 2k.i | Megawatt hours of generation served | 12,500,675 | 28,780,069 | Total Customers | NA | NA | NA | 27 |
| 2k.ii | Peak demand (megawatts) | 208,126 | 396,938 | Total Customers | NA | NA | NA | 30 |
| 2k.iii | Level of distributed generation (megawatt hours) | 236,150 | 438,526 | Total Customers | NA | NA | NA | 9 |
| 2k.iv | Available level of distributed generation (megawatts) | 121 | 179 | Total Customers | NA | NA | NA | 10 |

**Table B.4**. Summary of Qualitative Data

| Question | Count | Frequency Percentage (All Participants) |
|---|---|---|
| 3. Which of the following best describes your market conditions? | | |
| Regulated | 10 | 33.3% |
| Deregulated | 16 | 53.3% |
| Combination | 3 | 10.0% |
| No response | 1 | 3.3% |
| 4. In which industry segments does your organization participate? (Select all that apply) | | |
| Generation | 12 | 40.0% |
| Transmission | 27 | 90.0% |
| Distribution | 28 | 93.3% |
| Retail | 22 | 73.3% |
| 6. For the following, select all that are enabled through the real-time (cross-functional) data sharing from grid capabilities that you have implemented. | | |
| Planning has transitioned from estimation to measurement-based | 6 | 20.0% |
| Distributed intelligence and analytics are now available across functions and systems | 11 | 36.7% |
| Distributed intelligence and analytics are now available externally | 9 | 30.0% |
| Coordinated energy management of generation is available throughout your supply chain | 4 | 13.3% |
| 8. What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place that support smart grid investment by your utility? (Select all that apply) | | |
| None | 12 | 40.0% |
| Mandates (e.g., required installation of advanced meters) | 5 | 16.7% |
| Incentives | 7 | 23.3% |
| Regulatory recovery | 16 | 53.3% |
| 9a. Has your organization invested in smart grid? | | |
| Yes | 25 | 83.3% |
| No | 1 | 3.3% |
| No Response | 4 | 13.3% |
| 9c. Does your organization expect to make future smart grid investment? | | |
| Yes | 28 | 93.3% |
| No | 1 | 3.3% |
| No Response | 1 | 3.3% |
| 10. Does your organization have a demand response program? | | |
| Yes | 21 | 70.0% |
| No | 7 | 23.3% |
| No Response | 2 | 6.7% |
| 15. Do you have automated response to pricing signals for major energy using devices within a premise? | | |
| No | 13 | 43.3% |
| In development | 7 | 23.3% |
| A little (10%-30% of all customers) | 0 | 0.0% |
| To a great extent (30%-80% of all customers) | 0 | 0.0% |
| Completely (>80% of all customers) | 0 | 0.0% |
| No Response | 10 | 33.3% |
| 16. Do you have automated response to frequency signals for energy using devices within a premise? | | |
| No | 16 | 53.3% |
| In development | 4 | 13.3% |
| A little (10%-30% of all customers) | 0 | 0.0% |
| To a great extent (30%-80% of all customers) | 0 | 0.0% |
| Completely (>80% of all customers) | 0 | 0.0% |
| No Response | 10 | 33.3% |

**Table B.4**. (Contd)

| Question | Count | Frequency Percentage (All Participants) |
|---|---|---|
| 20. What interoperability maturity level in the Smart Grid Interoperability Maturity Model has been attained by your organization? | | |
| Initial (Level 1) | 6 | 20.0% |
| Managed (Level 2) | 5 | 16.7% |
| Defined (Level 3) | 11 | 36.7% |
| Quantitatively managed (Level 4) | 4 | 13.3% |
| Optimizing (Level 5) | 0 | 0.0% |
| No response | 4 | 13.3% |
| 22. Have you deployed the following security features? (Select all that apply). | | |
| Intrusion detection | 15 | 50.0% |
| Key management systems | 14 | 46.7% |
| Encrypted communications | 15 | 50.0% |
| Firewalls | 19 | 63.3% |
| Others (Please describe) | 4 | 13.3% |

### B.5.1.4 Graphic Summary of Qualitative Information

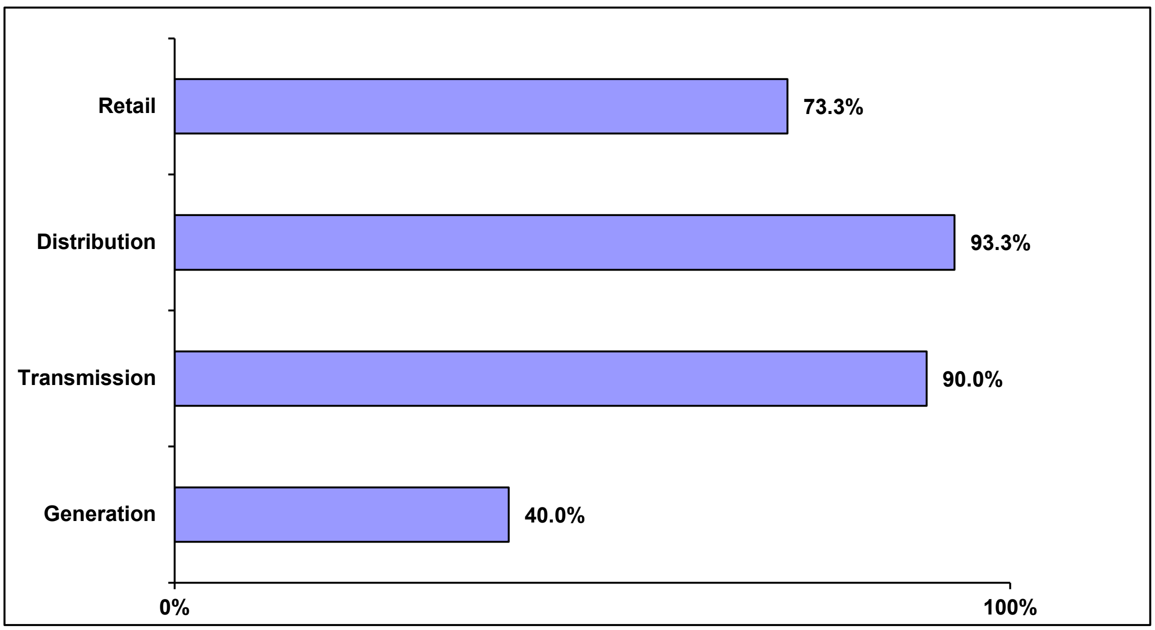



**Figure B.9**. Industry Segment

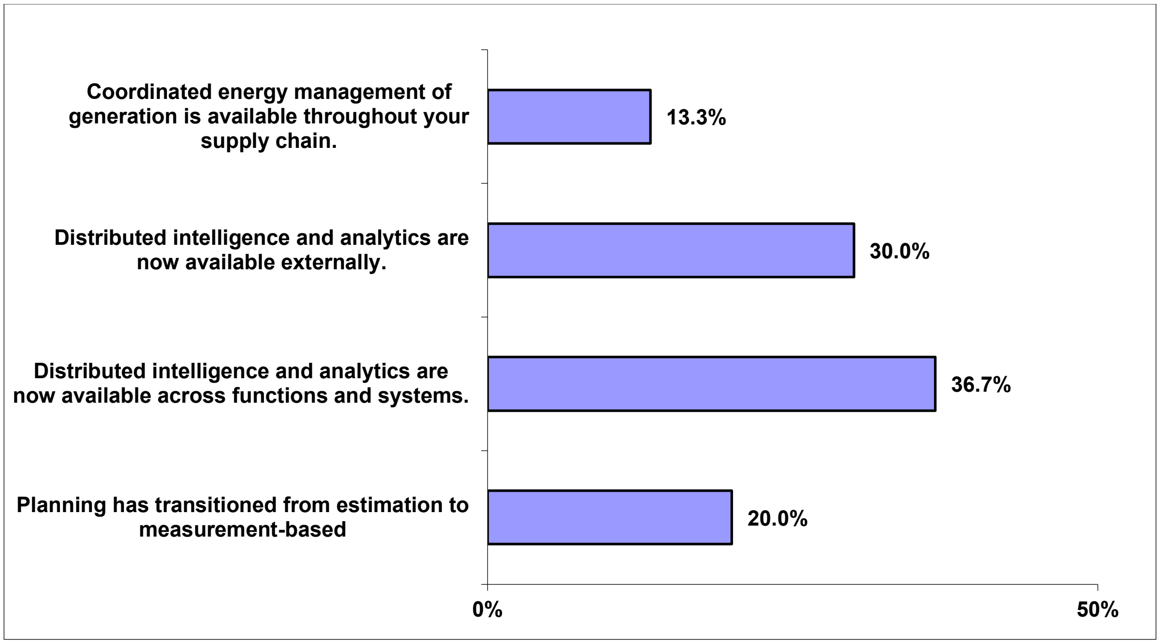



**Figure B.10**. Smart-Grid Activities Enabled by Smart-Grid Capabilities Implemented

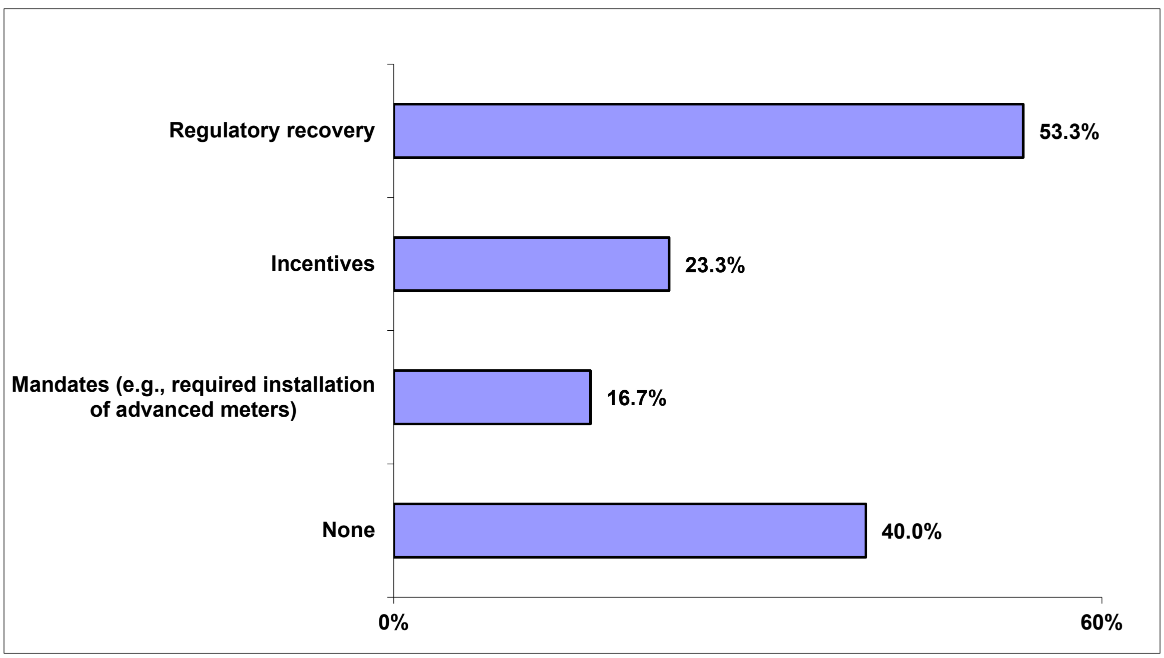



**Figure B.11**. Types of Regulatory Policies Supporting Smart-Grid Investment

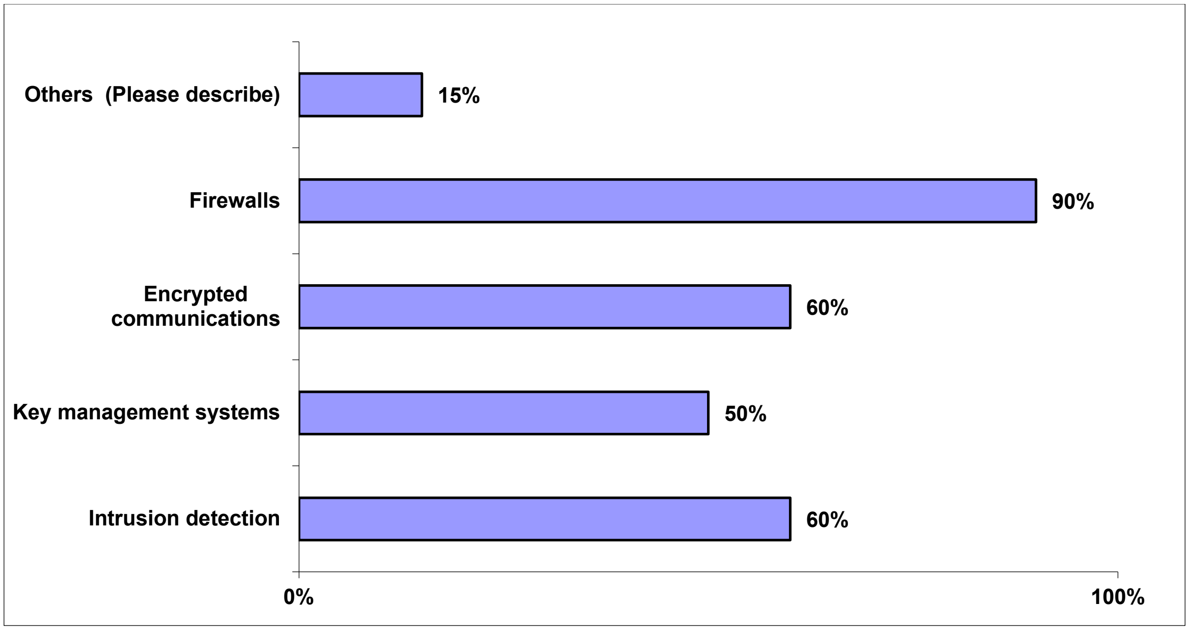



**Figure B.12**. Types of Security Features Deployed

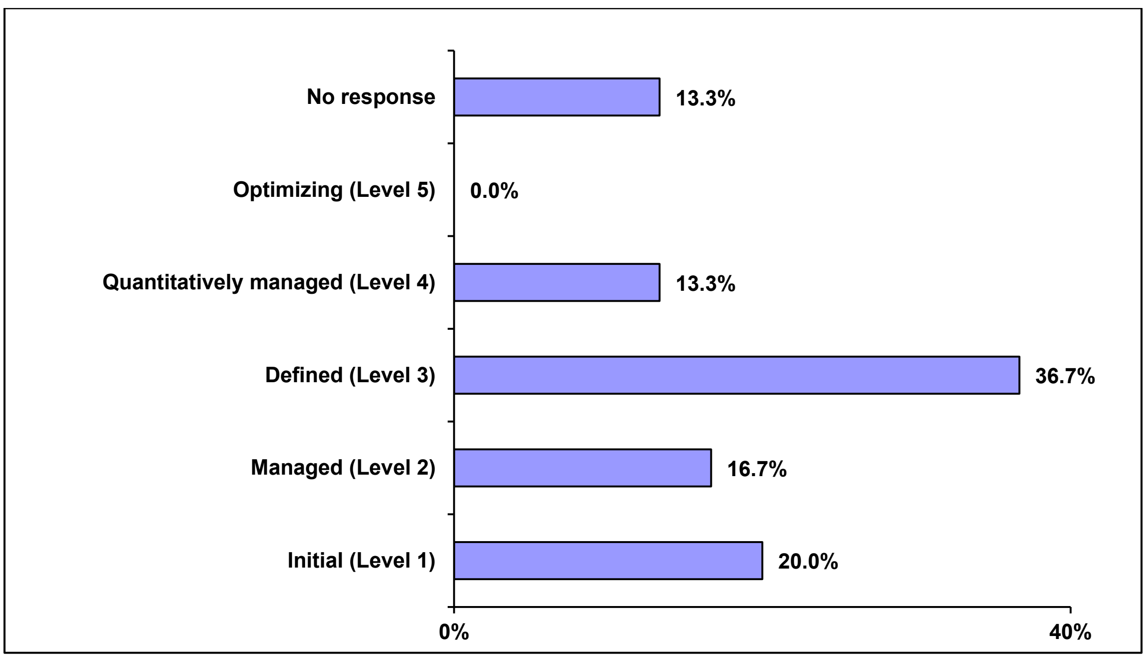



**Figure B.13**. Smart Grid Interoperability Maturity Model Interoperability Maturity Level

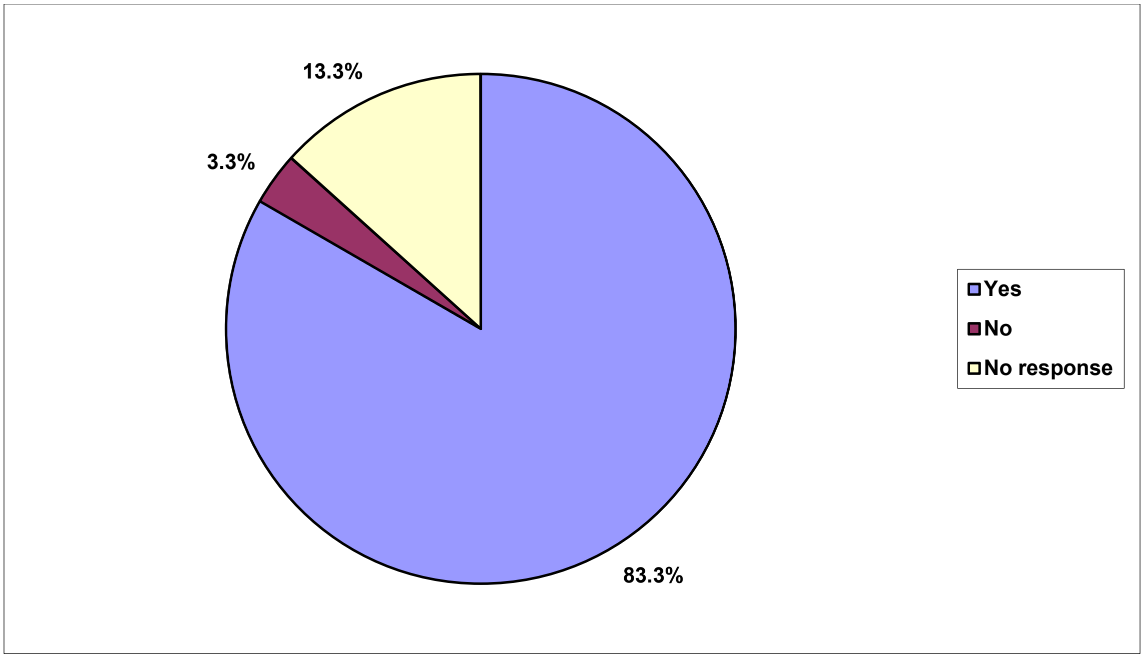



**Figure B.14**. Current Smart Grid Investment Participation

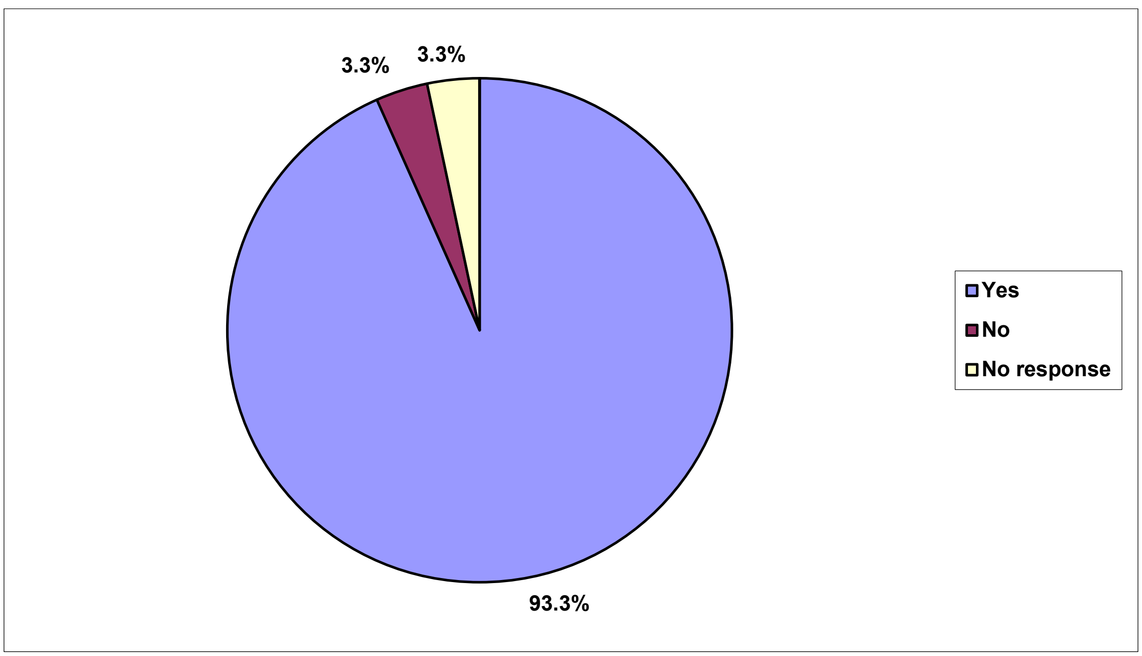



**Figure B.15**. Future Smart Grid Investment Participation

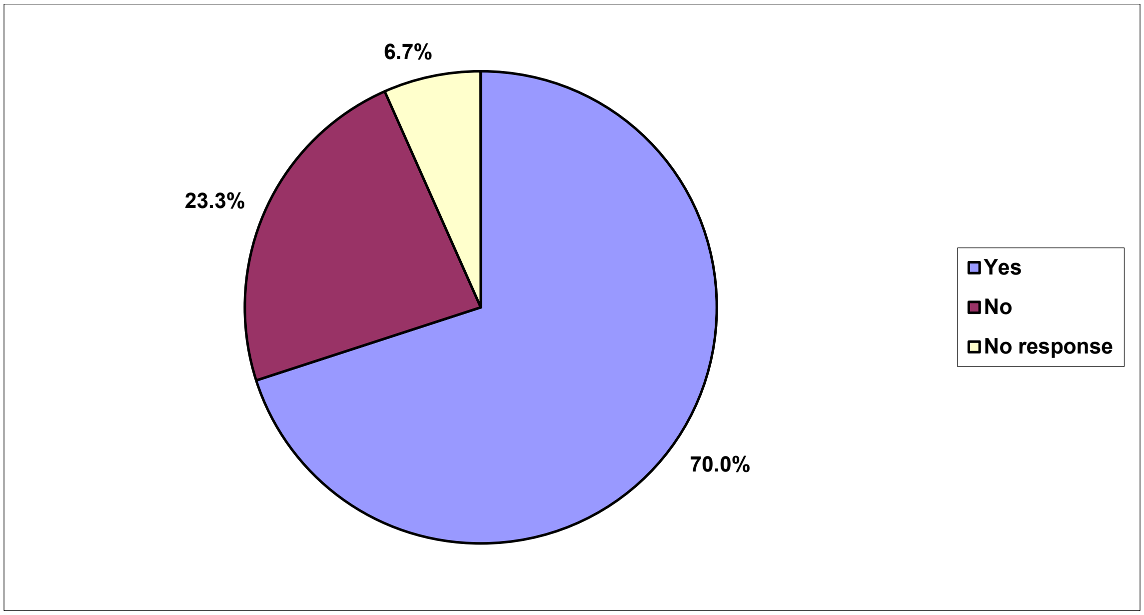



**Figure B.16**. Demand Response Programs in Place

## B.6 Insights for Future Data Collection

An additional objective during the course of the study was to gather insights about the selected metrics and interview questions to support future cycles of data collection and reporting. The key concern from participants was the level of effort to gather data requested in the interview. One respondent stated it would take six months to gather and report accurate information for some interview questions.

To this end, more rigorous data would become available through alignment with DOE smart grid data collection efforts throughout the reporting period. An opportunity also exists to align more closely with the SGMM data set as it is collected throughout the same reporting period. This would provide a broader and richer data set in support of the evaluation and reporting efforts. Both these improvements would need to be coordinated well in advance of initiating a future reporting effort.

## B.7 Interview Questions

Interview questions and the glossary used with electricity service providers are presented in the following section. Key terms used for interview questions are defined in the glossary.

### B.7.1 Interview Form and Questions

### B.7.2 Instructions

To support the data collection effort for this study, this interview assesses the current status of smart grid development, prospects for its future, and obstacles to progress. Scope includes:

- the prospects of smart grid development including costs and obstacles,

- regulatory or government barriers, and
- regional issues.

Data provided will be blinded and incorporated into APQC's databases and may be used to support APQC's mission as an education and research organization consistent with APQC's Benchmarking Code of Conduct (http://www.apqc.org/PDF/code_of_conduct.pdf). For purposes of identifying participating organizations, your organization's name will be listed as a study participant, as appropriate. In exchange for completing this interview, you'll receive a custom report of interview results. This study is sponsored by the U.S. Department of Energy and is performed by the Pacific Northwest National Laboratory.

### B.7.3 General Instructions

1. If you do not have the exact number for an answer, please provide a reasonable approximation. If you cannot provide a reasonable approximation, please leave the answer blank.
2. This interview has a glossary that defines many of the terms used in this interview.
3. Please direct interview-related questions to APQC 713-681-4020.

### B.7.4 Contact Information

First Name
Last Name
Title
Company Name (include division if applicable)
Address Line 1
Address Line 2
City
State
Postal Code
Phone
Business Email
Functional Area

### B.7.5 Interview Questions and Glossary

1. Please provide the end date of the 12-month period for which you will be providing data in this interview (e.g., Dec 31, 2011).

2. Please provide the following demographic information:
    a. Percentage of automated distribution substations
    b. Percentage of distribution substations with outage detection
    c. Percentage of circuits with outage detection
    d. Percentage of intelligent electronic devices (IEDs) with communications on your grid
    e. Percentage of relays that are electromechanical
    f. Percentage of relays that are microprocessor
    g. Number of employees
    h. Total distribution of customer count:
        I. Residential
        II. Commercial
        III. Industrial
    i. Average distribution customer load (kW):
        i. Residential
        ii. Commercial
        iii. Industrial
    j. Electric meter count (distribution):
        i. Residential:
            1. Advanced Metering Infrastructure (AMI)
            2. Total
        ii. Commercial:
            1. AMI
            2. Total
        iii. Industrial:
            1. AMI
            2. Total
    k. Megawatts:
        i. Megawatt hours of generation served
        ii. Peak demand (Megawatt)
        iii. Level of distributed generation (Megawatt hours)
        iv. Available level of distributed generation (Megawatts)
    l. Size of service territory in square miles
    m. Total number of transmission lines
    n. Number of substations by voltage class:
        i. Less than 13kV
        ii. Between 13kV and 35kV
        iii. Greater than 35kV

3. Which of the following best describes your market conditions?
    a. Regulated
    b. Deregulated
    c. Combination (service area includes both)

4. In which industry segments does your organization participate? (select all that apply)
    a. Generation
    b. Transmission
    c. Distribution
    d. Retail

5. What is the number of customers enrolled in the following time-based programs:

a. Critical Peak Pricing:
    i. Residential
    ii. Commercial
    iii. Industrial
    iv. Not applicable, we do not have a Critical Peak Pricing program
b. Real Time Pricing:
    i. Residential
    ii. Commercial
    iii. Industrial
    iv. Not applicable, we do not have a Real Time Pricing program
c. Time of Use:
    i. Residential
    ii. Commercial
    iii. Industrial
    iv. Not applicable, we do not have a Time of Use program
d. Other, please specify:
    i. Residential
    ii. Commercial
    iii. Industrial

6. For the following, select all that are enabled through the real-time (cross functional) data sharing from smart grid capabilities you have implemented.
    a. Planning has transitioned from estimation to measurement-based
    b. Distributed intelligence and analytics are now available across functions and systems (e.g., data collected from meters or at substation automation is available for forecasting, asset management, etc. within your business)
    c. Distributed intelligence and analytics are now available externally (e.g., data collected from meters or at substation automation is available for forecasting, asset management, etc. to the other organizations that make up the end-to-end energy delivery chain)
    d. Coordinated energy management of generation is available throughout your supply chain (e.g. system operations and retail market functions can call distributed resources for emergencies, day ahead, hour ahead, etc.)

7. Please provide the following information regarding SCADA:
    a. SCADA points per substation
    b. Total SCADA points shared per substation (ratio)
    c. Percentage of transmission-level Phasor Measurement Unit (PMU) data points shared multi-laterally

8. What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place that support smart grid investment by your utility?
    a. None
    b. Mandates (e.g., required installation of advanced meters)
    c. Incentives
    d. Regulatory recovery

9. Please provide the following information regarding smart grid investment:
    a. Has your organization invested in smart grid?
        i. Yes
        ii. No
    b. If yes, what percentage of your smart grid investment to date has been explicitly recovered through the rate case?
    c. Does your organization expect to make future smart grid investment?
        i. Yes
        ii. No
    d. If yes, what percentage of your future smart grid investment do you expect to recover through rate recovery?

10. Does your organization have a demand response program?
    i. Yes
    ii. No

11. Please provide the following information regarding automated circuits:
    a. Customers served by automated circuits
    b. Total load served by automated circuits (Megawatt hours)

12. Please provide the following information regarding net metering programs:
    a. Number of customers that are participating in net metering programs
    b. Amount of kW capacity of residential distributed generation that is participating in net metering programs
    c. Amount of energy (kWh) delivered from residential distributed generation to the grid

13. What is your energy storage capacity as a percentage of total capacity on grid (batteries, flywheels, thermal, pumped hydro)?

14. What is your non-dispatchable, non-controllable renewable generation as a percentage of total capacity on grid?

15. Do you have automated response to pricing signals for major energy using devices within a premise?
    a. no
    b. in development
    c. a little (10% - 30% of all customers)
    d. to a great extent (30% - 80% of all customers)
    e. completely (>80% of all customers)

16. Do you have automated response to frequency signals for energy using devices within a premise?
    a. no
    b. in development
    c. a little (10% - 30% of all customers)
    d. to a great extent (30% - 80% of all customers)
    e. completely (> 80% of all customers)

17. Please provide the following reliability measures:
    a. Predicted SAIFI
    b. Actual SAIFI
    c. Predicted SAIDI
    d. Actual SAIDI

e. Predicted MAIFI
f. Actual MAIFI

18. Please provide the following regarding capacity: :
    a. Yearly average and average peak capacity factor for a typical mile of transmission line (%)
    b. Yearly average and average peak capacity factor per mile of transmission line (%)
    c. Yearly average and average peak distribution-transformer capacity factor (%)

19. Please provide the following information regarding dynamic rating capability:
    a. Does your organization's lines have dynamic rating capability?
        i. Yes
        ii. No
    b. If yes, please provide the following:
        i. What number of lines have dynamic line rating?
        ii. What is the average transmission transfer capacity expansion due to use of dynamic rather than fixed transmission line ratings?

20. What interoperability maturity level in the Smart Grid Interoperability Maturity Model has been attained by your organization (Interoperability Maturity Level: see definitions in glossary)?
    a. Optimizing (Level 5)
    b. Quantitatively managed (Level 4)
    c. Defined (Level 3)
    d. Managed (Level 2)
    e. Initial (Level 1)

21. What is your percentage of customer complaints related to power quality issues (excluding outages)?
    a. Residential
    b. Commercial
    c. Industrial

22. Have you deployed the following security features? (Select all that apply)
    a. Intrusion detection
    b. Key management systems
    c. Encrypted communications
    d. Firewalls
    e. Others (Please describe)

## B.8 Glossary

| Term | Definition |
|---|---|
| **Advanced metering infrastructure** | Meters that measure and record usage data at hourly intervals or more frequently, and provide usage data to both consumers and energy companies at least once daily. Data is used for billing and other purposes. Advanced meters include basic hourly interval meters, meters with one-way communication, and real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data. Involves AMI meters that have been deployed that are capable of hourly data. |
| **Automated circuits** | An automated circuit is a distribution feeder that uses intelligent devices to provide fault detection, isolation and restoration logic in a group of reclosers, switches, or a combination of both. |
| **Automated substations** | Substation automation refers to a system that enables remote operation, monitoring, coordination and control of the distribution components contained within the substation. Intelligent electronic devices (IEDs) such as remote terminal units using high-speed |

| | |
|---|---|
| | microprocessors in a centralized control center provide for control, operation and protection. Applications and data of interest may include remote access to IED/relay configuration ports, waveforms, event data, diagnostic information, video for security or equipment status assessment, metering, switching, volt/VAR management, and others that maintain uninterrupted power services to the end users. If the substation is automated at all, it is counted. |
| **Capacity factor** | A capacity factor (CF) is the fraction of energy that is generated by or delivered through a piece of power system equipment during an interval, compared to the amount of energy that could have been generated or delivered had the equipment operated at its design or nameplate capacity. |
| **Circuits with outage detection** | Include breakers, reclosers, or fuses. "Circuits" mean downstream from substations. |
| **Critical peak pricing** | Reflects elevated prices from anticipated high wholesale market prices or power system emergency conditions, resulting from critical events during a specified time period (e.g., 3 p.m.–6 p.m. on a hot summer weekday). Two variants of this type of rate design exist: one in which the time and duration of the price increase are predetermined when events are called and another in which the time and duration of the price increase may vary based on the electric grid's need to have loads reduced. |
| **Distribution substations with outage detection** | Downstream breakers and fuses that have communication with the utility and identify that something has popped. |
| **Distribution transformer** | Transformers at the substation, not customer transformers. |
| **Explicitly recovered through the rate case** | Investment is built into the rate case and it is approved by the PUC, as opposed to building it into the cost of doing business through depreciation. A rider and a rate case would both be considered explicit. |
| **Industrial customers** | Customers that have factories or are involved in manufacturing; they typically have the highest energy needs. Other customers are residential and commercial. |
| **Interoperability maturity level** | Level 5 – Optimizing:<br>Continually improve processes based on quantitative understanding of the causes of variation: Exchange specifications in an interoperability area are based on standards with planned upgrade processes driven by quantitative feedback from implementations and the needs of the community.<br>Level 4 – Quantitatively Managed:<br>Quantitative objectives for performance measurement and management: Processes for appraising the effectiveness of the specifications and standards used in an interoperability area are in place and supported by the community. Successes and deficiencies are noted. Implementations are certified interoperable.<br>Level 3 – Defined:<br>Quantitative objectives for performance measurement and management: Exchange specifications in an interoperability area are defined and use standards adopted by the community. Well-developed interoperability verification regimes are in place. Participants claim standards compliance.<br>Level 2 – Managed:<br>Planned and executed in accordance with policy: Exchange specifications and testing processes exist in an interface area on a project basis, but are not defined for the community. Some standards are referenced or emerging, but may not be consistently applied.<br>Level 1 – Initial:<br>Ad hoc and chaotic: Unique, custom-developed interface area. Requires significant custom engineering to integrate with other components. No agreed-upon standards between parties. Interoperability is difficult to achieve and very expensive to maintain. |
| **Net metering programs** | A net metering program provides utility customers with small grid-connected generation the ability to offset electricity provided by the utility during an applicable billing period, usually at the retail price. |
| **MAIFI** | Momentary Average Interruption Frequency Index (MAIFI) is the average number of momentary interruptions that a customer would experience during a given period. |
| **Real-time pricing** | Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day ahead or hour-ahead basis. |

| | |
|---|---|
| **SAIFI** | System Average Interruption Frequency Index (SAIFI) is the average number of interruptions that a customer would experience. |
| **SAIDI** | System Average Interruption Duration Index (SAIDI) is the average outage duration for each customer served. |
| **SCADA** | Supervisory control and data acquisition: a system of remote control and telemetry used to monitor and control the transmission and/or distribution system. |
| **SCADA points** | The number of grid measurement points (e.g., voltage, power flow, etc.) available from grid assets within your SCADA capabilities. |
| **SCADA points shared** | Points shared between participants outside the control of the substation (utility, ISO) |
| **Smart grid** | "Smart grid" generally refers to a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation. These systems are made possible by two-way communication technology and computer processing that has been used for decades in other industries. They are beginning to be used on electricity networks, from the power plants and wind farms all the way to the consumers of electricity in homes and businesses. |
| **Time of use** | A rate schedule in which the utility customer is charged different amounts for power based on the time of day and season. |
| **Transmission-level PMU measurement points shared multi-laterally** | Transmission line ratings such as 69 kV, 115 kV, 230 kV, 500 kV.<br>PMU sharing (communicating) with three or more entities such as between two utilities, reliability coordinators and/or a balancing authority |
| **Yearly average and average peak capacity factor for a typical mile of transmission line (CF trans line) %** | See capacity factor definition above.<br><br>Formula: {Transmitted energy (MWh) / [Line Power Rating (MVA) × 8760 (hours)]} ×100<br>This is true bulk power transmission—i.e., not sub-transmission, at least 20 miles long. |
| **Yearly average and average peak capacity factor per mile of transmission line (CF per mile trans line) %** | See capacity factor definition above.<br><br>Formula: [Line Distance (miles) × CF trans line] / [Line Distance (miles)] |
| **Yearly average and average peak distribution-transformer capacity factor (CF Dist Xfmr) %** | See capacity factor definition above.<br><br>Formula: {Transformer Energy (MWh) / [Transformer Rating (MVA) × 8760 (hours)]} ×100<br><br>Pertains to transformers at the substation, not the customer transformers. |