

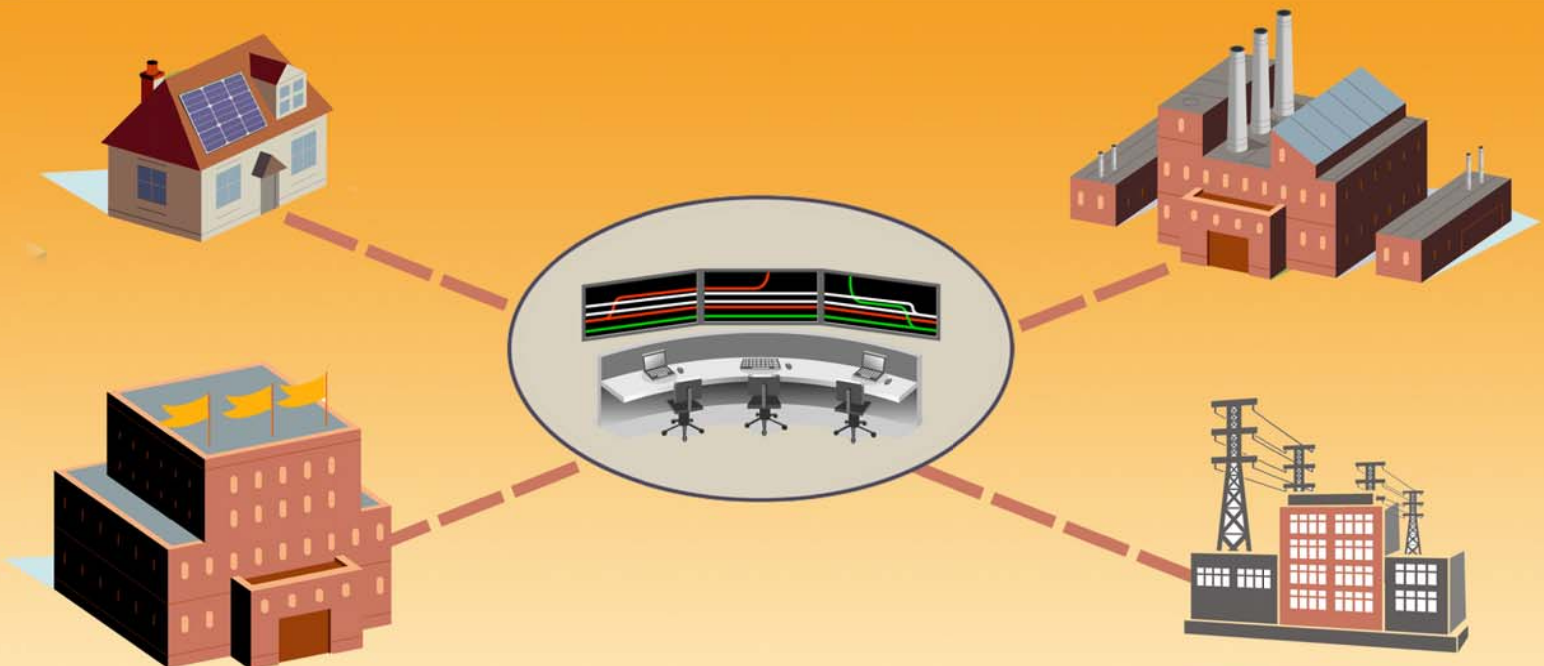


FEDERAL ENERGY REGULATORY COMMISSION

A S S E S S M E N T O F

Demand Response & Advanced Metering

STAFF REPORT



NOVEMBER 2011

2011

Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

November 2011

The opinions and views expressed in this staff report do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

ACKNOWLEDGEMENTS

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FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

Pursuant to Energy Policy Act of 2005 section 1252(e)(3)

November 2011

The Federal Energy Regulatory Commission staff (Commission staff) presents information in this sixth annual Assessment of Demand Response and Advanced Metering (report). This report fulfills a requirement of the Energy Policy Act of 2005 (EPAcT 2005) section 1252(e)(3)¹ that the Federal Energy Regulatory Commission (FERC or Commission) prepare and publish an annual report, by appropriate region, that assesses electricity demand response resources, including those available from all consumer classes.²

Commission staff reviewed information from a variety of sources³ to develop this year's report, which provides information on demand response and advanced metering with an emphasis on results, activities, and regulatory actions taken over the last year. Based on the information reviewed, it appears that:

- The penetration of advanced meters is up from 8.7 percent in 2009 to 13.4 percent;
- Demand response potential in organized markets operated by the Electric Reliability Council of Texas (ERCOT), Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) increased by more than 16 percent since 2009;
- Demand responded to peak load emergency conditions in ERCOT and the RTO and ISO organized markets; and
- Federal and state regulators and others continue to focus on demand response, taking actions to remove barriers to wholesale demand response and develop policies to address smart grid.

The report is organized according to the six requirements included in section 1252(e)(3) of EPAcT 2005, which directs the Commission to identify and review:

¹ Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (EPAcT 2005 section 1252(e)(3)).

² The Commission submitted the first report, the *Assessment of Demand Response and Advanced Metering: Staff Report*, Docket No. AD06-2, August 7, 2006 (referred to here as the 2006 FERC Demand Response Report), available at <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>. The 2007, 2008, 2009 and 2010 annual reports are also available at <http://www.ferc.gov/industries/electric/indus-act/demand-response.asp>.

³ Information was compiled from readily accessible data and reports, Energy Information Administration surveys, Regional Transmission Organization (RTO) and Independent System Operator (ISO) annual reports, and discussions with market participants and industry experts. Commission staff has not independently verified the accuracy of all data presented herein.

- (A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;
- (B) existing demand response programs and time-based rate programs;
- (C) the annual resource contribution of demand resources;
- (D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- (E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and
- (F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

Each of the above requirements is addressed below in a separate section. Within that section, information concerning state, federal and industry activities is also provided.

(A) Saturation and penetration rate of advanced meters

Recent data from various sources give differing estimates of the penetration rate⁴ of advanced meters, but all estimates increase over the period 2007 to 2011. A U.S. Energy Information Administration (EIA) sample of 420 utilities reported 9.7 million (or 13.4 percent) advanced meters as of June 2011.⁵ EIA also collects information on advanced meters annually on the Form EIA-861.⁶ In 2009, entities reported that 9.6 million advanced meters were in use out of approximately 148.4 million meters in total, indicating a penetration rate for 2009 of 6.5 percent. The most recent FERC Survey of advanced meters showed a penetration rate of 8.7 percent in 2009.⁷

Other sources also report increasing numbers of advanced meter installations over the past year. For example, data collected by the Institute for Electric Efficiency (IEE) indicates that advanced meters represent about 18 percent of all meters in the U.S. as of September 2011.⁸ The high penetration rate from IEE data may be because, unlike the Commission and EIA, its data include

⁴ In this report, “penetration rate” means the percentage of all installed meters that are advanced meters.

⁵ The Form EIA-826, “Monthly Electric Utility Sales and Revenue Report with State Distributions,” is used to collect data on retail sales of electricity and associated revenue, each month, from a statistically chosen sample of electric utilities in the United States. The respondents to the Form EIA-826 are chosen from the Form EIA-861, “Annual Electric Utility Report.” (<http://205.254.135.24/cneaf/electricity/page/eia826.html>). The EIA-826 sample population was not designed specifically to collect the number of advanced meters. The data items for advanced meters are a recent addition to the preexisting EIA-826 form.

⁶ The Form EIA-861 is completed by electric power industry entities including: electric utilities, all DSM (Demand-Side Management) Program Managers (entities responsible for conducting or administering a DSM program), wholesale power marketers (registered with the Federal Energy Regulatory Commission), energy service providers (registered with the States), and electric power producers. Responses are collected at the operating company level (not at the holding company level).

⁷ 2010 FERC Demand Response Report.

⁸ Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (September 2011) (“IEE Deployments”). Penetration rate based on 27.3 million installed smart meters (IEE) and 148.4 million U.S. electric consumers (Energy Information Administration, Form EIA-861 Data, 2009).

advanced meters that have been installed but which have not yet been activated for advanced metering purposes.

The growth in advanced meter installations may be attributable in part to funding for advanced meters and advanced meter systems through the Smart Grid Investment Grant (SGIG) program provided for under the American Recovery and Reinvestment Act of 2009 (Recovery Act).⁹ As of September 28, 2011, approximately 7.2 million advanced meters have been installed using Recovery Act funding. Ultimately, 15.5 million advanced meters are expected to be installed under SGIG.¹⁰ IEE predicts that about 65 million advanced meters will be installed nationwide by 2015.¹¹

Table 1 summarizes the available information on advanced meter installations.

Table 1: Estimates of Advanced Meter Penetration Rates

Source of No. of Advanced Meters	Reference Date (Month/Year)	Advanced Meter Penetration Rates (advanced meters as a % of total meters)	Number of Advanced Meters (millions)	Total Number of Meters (millions)
2008 FERC Survey	Dec 2007	4.7%	6.7 ¹	144.4 ¹
2010 FERC Survey	Dec 2009	8.7%	12.8 ²	147.8 ²
EIA-861 Annual Survey	Dec 2009	6.5%	9.6 ³	148.4 ³
EIA-826 Monthly Survey	June 2011	13.4%	9.7 ⁴	72.4 ⁴
Institute for Electric Efficiency	Sept 2011	18.4%	27.3 ⁵	148.4 ³

Sources:
¹ FERC, Assessment of Demand Response and Advanced Metering staff report (December 2008).
² FERC, Assessment of Demand Response and Advanced Metering staff report (February 2011).
³ Energy Information Administration, Form EIA-861 Final Data File for 2009 (<http://www.eia.gov/cneaf/electricity/page/eia861.html>).
⁴ EIA-826 Advanced Metering Spreadsheets (June 2011), (http://www.eia.gov/Ftproot/pub/electricity/netmetering_green_pricing/f826advancedmetering2011.xls).
⁵ Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (September 2011).

Note: Commission staff has not independently verified the accuracy of EIA or IEE data.

Developments and issues in advanced metering

As indicated above, there has been an increase in the penetration of advanced meters between 2007 and 2011. Federal, state and local governmental entities as well as industry stakeholders have been actively developing policies and supporting infrastructure to facilitate and address issues concerning the deployment and use of advanced metering. As advanced metering deployment continues and achieves greater penetration, issues associated with use of advanced metering and associated smart grid technologies have gained in importance. Discussed below are federal and state developments, privacy concerns and health issues.

⁹ American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5.

¹⁰ U.S. Department of Energy,

http://www.smartgrid.gov/recovery_act/tracking_deployment/ami_and_customer_systems.

¹¹ IEE Deployments.

Interoperability standards

The Energy Independence and Security Act of 2007 (EISA) gave the National Institute of Standards and Technology (NIST) “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...” In addition to the issue of meter upgradeability which was addressed in 2009¹², meter data formats and translation facilitation, and meter communication with retail devices involve advanced metering.

NIST’s Priority Action Plan 5 (**Standard Meter Data Profiles**) and Priority Action Plan 6 (**Translate ANSI C12.19 to and from a Common Semantic Model**) are efforts to develop a common format for retrievable meter data and to develop a common form to which meter information may be translated. According to NIST, these standards are intended to greatly reduce the time needed by utilities (and others requiring meter data) to implement smart grid functions such as demand response and real-time usage information. Both plans are expected to be completed in late 2011.

NIST’s Priority Action Plan 18 (**SEP 1.x to SEP 2.0 Transition and Coexistence**) will develop requirements for the coexistence of and migration between two versions of a system used to communicate between meters and consumer devices. According to NIST, the earlier version supports home area networking, pricing of multiple commodities, encryption, direct load control, and demand response; and the newer version will add support for multiple types of networking and security, international standards, electric vehicles, and distributed energy resources. Priority Action Plan 18 is expected to be completed late in 2011.¹³

State and Federal regulatory bodies have encouraged stakeholders to engage in the NIST process for developing standards. The National Association of Regulatory Utility Commissioners (NARUC) in a resolution issued in July 2011 emphasized the desirability of smart grid standards and encouraged parties to participate in the Smart Grid Interoperability Panel process.¹⁴ The Commission in a July 2011 order encourages utilities, smart grid product manufacturers, regulators and others to actively participate in the NIST interoperability framework process.

Development of state-based progress and performance metrics

Progress and performance metrics allow states to gauge installation rates and performance results for numerous components of a utility’s advanced metering infrastructure deployment and operational strategy.

Since the last Commission staff annual report, several states made progress on developing these metrics. The Illinois Commerce Commission established the Illinois Statewide Smart Grid

¹² National Electrical Manufacturers Association, NEMA Smart Grid Standards Publication SG-AMI 1-2009, September 25, 2009, available at <http://www.nema.org/stds/sg-ami1.cfm>.

¹³ NIST Smart Grid Collaborative, <http://collaborate.nist.gov/wiki-ssgrid/bin/view/SmartGrid/PAP18SEP1To2TransitionAndCoexistence>.

¹⁴ NARUC, Policy Resolutions Passed by the Board of Directors of the National Association of Regulatory Commissioners (July 11, 2011 p. 6).

Collaborative (ISSGC), which issued a final report in October 2010.¹⁵ In February 2011, the California Public Utilities Commission (California PUC) received comments on a “Report on Consensus and Non-Consensus Smart Grid Metrics” that was submitted by three investor-owned utilities.¹⁶ In May 2011, the Maryland Public Service Commission received an Advanced Metering Infrastructure Performance Metrics Reporting Plan submitted by two investor-owned utilities on behalf of a working group led by public service commission staff. The metrics in the Maryland plan consider cost, project execution and delivery, operational benefits, and consumer education.¹⁷

Other state legislative and regulatory activity

- **Colorado.** On January 20, 2011, the Colorado Smart Grid Task Force published a set of recommendations for the Governor, General Assembly, and the Colorado Public Utilities Commission (Colorado PUC) to consider. Among its consensus findings, it recommended open communication standards for metering protocols (as defined by NIST), the exploration of time-based pricing, and a “technology ‘platform,’ or base operating system of protocols and communications ...such that all new software systems, hardware devices and new products can be ‘plugged in’ to the network and immediately recognize and be recognized by the network.”¹⁸ The task force also noted that AMI can facilitate distributed generation, variable energy resources, and demand response for consumers.
- **Kentucky.** In March 2011, multiple stakeholders provided a joint response to Kentucky Public Service Commission (KPSC) staff’s Smart Meter and Smart Grid Guidance document. The response recommended that the Kentucky Commission undertake pilots and trials, focus on customer education, and resist implementing prescriptive requirements.¹⁹

¹⁵ ISSGC, *Illinois Statewide Smart Grid Collaborative: Collaborative Report*, September 30, 2010, available at <http://www.ilgridplan.org/Shared%20Documents/ISSGC%20Collaborative%20Report.pdf>.

¹⁶ California Public Utilities Commission, *Report on Consensus and Non-Consensus Smart Grid Metrics*, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and the Environmental Defense Fund, (submitted per Decision No.10-06-047), available at <http://docs.cpuc.ca.gov/efile/RULINGS/129001.pdf>.

¹⁷ Maryland Public Service Commission, *BGE Advanced Metering Infrastructure Performance Metrics Reporting Plan*, May 18, 2011, Case 9207: 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 Mechanism for the Recovery of Cost; Case 9208: In the Matter of the Application of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure, available at <http://webapp.psc.state.md.us/Intranet/home.cfm>.

¹⁸ Colorado Smart Grid Task Force, *Deploying Smart Grid in Colorado: Recommendations and Options* (undated), p. 10; available at http://rechargecolorado.com/images/uploads/pdfs/Deploying_Smart_Grid_in_Colorado_Recommendations_and_Options.pdf.

¹⁹ KPSC, Joint Case Participant Response: Consideration of the New Federal Standards of the Energy Independence and Security Act: In response to Kentucky PSC’s February 19, 2010 Guidance Document Letter, March 25, 2011, Case No. 2008-00408: Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007, p. 50, available at http://psc.ky.gov/pscscf/2008%20cases/2008-00408/20110325_Ig&e%20and%20ku_response.pdf.

- **New Jersey.** New Jersey’s draft Energy Master Plan issued in June 2011 calls for the expansion of advanced metering and dynamic pricing, the reduction of peak demand, and the assessment of smart grid demonstration projects.²⁰

In addition, several other states, including Massachusetts, Michigan, New York, Ohio, Oklahoma, Pennsylvania, and Texas have smart grid task forces, collaboratives or other groups, or specific proceedings evaluating advanced metering issues.²¹

Privacy of advanced metering data

The need for safeguards and standards to protect the privacy and security of customer usage data continues to be a key issue associated with advanced metering systems. While one of the potential benefits associated with advanced metering is the ability to measure and communicate customer usage at a much greater level of detail than traditional electro-mechanical meters, various stakeholder groups have raised concerns at the state and national levels regarding the use, privacy and security of the vast amount of detailed usage data produced by advanced meters.²² In response to these concerns, states and the federal government are working on privacy standards and policies. Policies under consideration include procedures and rules governing customer ownership, consent, access and use, delineation of responsibilities, security, as well as the sale and transfer of data.

At the federal level, the Obama Administration examined privacy issues in depth in its June 2011 smart grid policy framework report.²³ The report recommends that “State and Federal regulators should consider, as a starting point, methods to ensure that consumers’ detailed energy usage data are protected in a manner consistent with federal Fair Information Practice Principles and develop, as appropriate, approaches to address particular issues unique to energy usage.”²⁴

A number of states also took action in the past year to protect consumer data privacy. For example, as a result of legislation enacted in 2010 (SB 1476), the California PUC adopted privacy rules for the three investor-owned utilities addressing disclosure and protection of customer energy usage data generated by advanced metering, and the investor-owned utilities must file tariff changes that will provide third parties with access to a customer’s usage and billing information (e.g., 15-minute or hourly price, usage and cost data) when authorized by the

²⁰ State of New Jersey, *2011 Draft Energy Master Plan*, June 2011, available at <http://www.nj.gov/emp/docs/pdf/2011%20Draft%20Energy%20Master%20Plan.pdf>.

²¹ Association for Demand Response and Smart Grid, “Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: May 2010 – June 2011”, June 2011. Also, the Edison Electric Institute maintains a summary of state decisions, i.e., EEI Summary of State Regulatory Smart Grid Decisions, August 2011, available at <http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Pages/StatePolicyResearch.aspx>.

²² See U.S. Department of Energy, *Data Access and Privacy Issues Related to Smart Grid Technologies*, October 5, 2010, available at http://www.doe.gov/sites/prod/files/gcprod/documents/Broadband_Report_Data_Privacy_10_5.pdf.

²³ Executive Office of the President, *A Policy Framework for the 21st Century Grid: Enabling Our Secure Energy Future*, June 2011, available at <http://www.whitehouse.gov/sites/default/files/microsites/ostp/nstc-smart-grid-june2011.pdf>.

²⁴ *Id.* at 46.

customer.²⁵ The decision adopts the Fair Information Practice Principles. In addition to the privacy rules for the three investor-owned utilities, the California PUC also ruled that if specific electric utilities²⁶ file applications to deploy advanced metering systems, these utilities must also address how the privacy rules should apply to their operations.

The Colorado PUC issued proposed amendments to the state's smart data privacy rules, which would change or add new definitions to the rules, provide standards for data collection with a smart meter, require approval to disclose customer data to affiliates and third parties, limit smart meter reading to kilowatt and kilowatt-hours, and establish specific amounts for civil penalties for infringement of the new rules.²⁷ After two hearings and a workshop, the matter was referred to an Administrative Law Judge (ALJ), who ultimately issued a decision on August 29, 2011 recommending adoption of the amendments.²⁸

The ALJ addressed issues including the definition of "customer data," the availability of analog meters, customers' ability to "freeze" data sharing even after granting consent to share data, limited liability for utilities that disclose customer information in compliance with Commission rules, and the form by which customers consent to third-party access to their data.²⁹

In February 2011, the Public Utilities Commission of Ohio (PUCO) issued an order requesting comments to identify issues or topics to be considered regarding consumer privacy protection or customer data access, and advanced specific questions for stakeholder input.³⁰ Oklahoma enacted the Electric Usage Data Protection Act in May 2011, which establishes standards to govern the access to and use of customer usage data by electric utilities, customers of electric utilities, and third parties.³¹ In June 2011, Maine enacted legislation requiring the Maine Public Utilities

²⁵ California Public Utilities Commission, (Date of Issuance, 7/29/2011), Rulemaking 08-12-009: Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System, available at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/140369.htm.

²⁶ Bear Valley Electric Service, Mountain Utilities, PacifiCorp, and the California Pacific Electric Company.

²⁷ Colorado Public Utilities Commission, Docket No. 10R-799E, In the Matter of the Proposed Rules Relating to Smart Grid Data Privacy for Electric Utilities, 4 Code of Colorado Regulations 723-3, Notice of Proposed Rulemaking, November 3, 2010, Decision No. C10-1192.

²⁸ Colorado Public Utilities Commission, Recommended Decision of Administrative Law Judge G. Harris Adams Adopting Rules, August, 29, 2011, Decision No. R11-0922.

²⁹ Colorado also intends to have a future rulemaking on data access and sharing, including how to value aggregated data sold to marketers.

³⁰ See PUCO, Case No: 11-277-GE-UNC: In the Matter of the Review of the Consumer Privacy Protection, Customer Data Access, and Cyber Security Issues Associated with Distribution Utility Advanced Metering and Smart Grid Programs, available at <http://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=11-0277>, and PUCO, Consumer Privacy and Customer Data Access Issues, available at <http://www.puco.ohio.gov/emplibrary/files/media/smartgrid/CONSUMER%20PRIVACY%20AND%20CUSTOMER%20DATA%20ACCESS%20ISSUES.pdf>.

³¹ Oklahoma State Legislature, HB 1079 of 2011, Electric Utility Data Protection Act, available at <http://www.oklegislature.gov/BillInfo.aspx?Bill=HB1079&Tab=0>.

Commission to examine state and federal cyber security and privacy requirements, monitor federal cyber security initiatives, and report findings and recommendations to the legislature.³²

Radio frequencies and health

Another publicly noted concern regarding the deployment of advanced metering is the possible linkage between the radio frequencies used to transmit meter data wirelessly and human health.³³ The radio frequency (RF) emissions associated with advanced metering have not been proven to present a risk to human health, but concerns about a possible linkage continue.³⁴

In response to customer concerns, several states examined the health concerns raised by some customers and developed policies to address these concerns. For example, in December 2010, the California Public Utilities Commission dismissed a motion to consider the potential danger of advanced metering, concluded that RF emissions are under the purview of the FCC, and the RF emissions from advanced meters are “one/six thousandth of the Federal health standard at a distance of 10 feet from the Smart Meter and far below the RF emissions of many commonly used devices.”³⁵ Nevertheless, in March 2011, California Public Utilities Commission President Peevey asked Pacific Gas & Electric to develop a customer opt-out proposal to address customer concerns. PG&E’s initial proposal identified two options as economic and technically feasible: turning off the radio transmitter in the customers’ meters or relocating the meter to a different location on the property at the customer’s expense.³⁶

In May 2011, the Maine Public Utilities Commission required Central Maine Power to offer a similar opt-out program due to RF concerns. Under this opt-out program, customers can either have the radio transmitter turned off or may continue to use the existing electro-mechanical meter.³⁷ Central Maine Power customers can select either of these customized metering options as a non-standard option and pay associated charges. The Maine Commission made no determination on the merits of health and safety concerns.³⁸

³² Maine State Legislature, Chapter 82 of the 125th Maine Legislature, available at http://www.mainelegislature.org/legis/bills/bills_125th/chapters/RESOLVE82.asp.

³³ See California Council on Science and Technology, *Health Impacts of Radio Frequency from Smart Meters*, January 2011, available at <http://www.ccst.us/publications/2011/2011smartA.pdf>.

³⁴ The Federal Communications Commission (FCC) advises that “exposure to very high RF intensities can result in heating of biological tissue and an increase in body temperature...[and] at relatively low levels of exposure to RF radiation, i.e., levels lower than those that would produce significant heating; the evidence for production of harmful biological effects is ambiguous and unproven.” Federal Communications Commission, Office of Engineering and Technology, *Radio Frequency Safety*, available at <http://transition.fcc.gov/oet/rfsafety/rf-faqs.html>.

³⁵ California Public Utilities Commission, Decision Granting Motion of Pacific Gas and Electric Company to Dismiss Application, Decision 10-12-001, December 6, 2010, available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/127604.pdf.

³⁶ California Public Utilities Commission, PG&E Smart Meter Opt-Out Proposal, available at <http://www.cpuc.ca.gov/PUC/energy/Demand+Response/pgeoptout.htm>.

³⁷ Maine Public Utilities Commission, Press Release, “MPUC Decides Smart Meter Investigation,” May 17, 2011, available at <http://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=245859&v=article08>.

³⁸ Maine’s Center for Disease Control published a final review concluding little evidence exists supporting health effect concerns. See Maine Center for Disease Control, *Executive Summary of Review of Health Issues Related to Smart Meters*, November 8, 2010, available at http://www.maine.gov/dhhs/boh/documents/Smart_Meters_Maine_CDC_Executive_Summary_11_08_10.pdf.

(B) Existing demand response programs and time-based rate programs

Commission staff surveyed existing demand response and time-based rate programs in 2010 (see 2010 FERC Demand Response Report) and intends to conduct another survey during 2012. Staff has not identified any additional data on levels of participation in demand response and time-based rate programs since the release of the 2010 FERC Survey.

(C) Annual resource contribution of demand resources

Based on publicly available sources of information, the potential resource contribution by demand response in Regional Transmission Organization (RTO) and Independent System Operator (ISO) markets operated in the U.S. increased by more than 16 percent from 27,189 megawatts (MW) in 2009 to 31,702 MW in 2010.

RTOs and ISOs publish recent data on demand response potential in their respective areas. Table 2 compares the reported data for calendar year 2009 to values for 2010 (or more recent values, where available) from RTO/ISO sources. Overall, the demand response resources' potential contribution in U.S. RTO/ISO markets increased by about 16 percent since 2009.³⁹

Demand response resources active during 2011

Demand response resources have made significant contributions to balancing supply and demand during system emergencies for several RTOs and ISOs in 2011. For example, very hot weather during July 2011 in the Eastern U.S. caused demand for electricity to approach record-setting levels. On July 21, the New York Independent System Operator (New York ISO) activated all of its registered demand response in the downstate region (more than 800 MW), and activated more than 2,000 MW of demand resources statewide the following day.⁴⁰

In the PJM Interconnection, L.L.C. (PJM) region, economic (non-emergency) demand response reached a peak reduction of 105 MW in reaction to high prices on July 21. On July 22, PJM activated demand resources in six Mid Atlantic zones, resulting in about 2,400 MW of peak reduction, mostly from emergency demand resources.⁴¹ ISO New England called for 643 MW of demand response on July 22, and estimated that about 663 MW of peak reduction resulted.⁴²

³⁹ The MW reported here represent the MW of demand response “registered” for participation and potential deployment in the relevant markets and programs, e.g., capacity markets, economic- and reliability-based programs.

⁴⁰ New York ISO, Press release, “Heat Pushes Power Demand to Near Record Level,” July 22, 2011, available at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2011/NYISO_-_Heat_Pushes_Power_Demand_to_Near_Record_Level_-_07_22_11_-_FINAL_FINAL.pdf.

⁴¹ PJM, *2011 Preliminary Emergency Load Management (ILR/DR) and Economic Demand Response summary*, October 7, 2011, available at [http://www.pjm.com/markets-and-operations/demand-response/~media/markets-ops/dsr/2011-preliminary-emergency-load-management-ilr-dr-and-economic-dr-summary.ashx](http://www.pjm.com/markets-and-operations/demand-response/~/media/markets-ops/dsr/2011-preliminary-emergency-load-management-ilr-dr-and-economic-dr-summary.ashx).

⁴² ISO Newswire, “Heat wave pushes NE demand to second-highest peak,” July 28, 2011, available at <http://www.isonewswire.com/updates/2011/7/28/heat-wave-pushes-ne-demand-to-second-highest-peak.html>.

Table 2: Demand Response Resource Potential at U.S. ISOs and RTOs

	2009 (MW)	Percent of 2009 Peak Demand ⁹	2010 except as noted (MW)	Percent of 2010 Peak Demand ⁹
California ISO	3,267 ¹	7.1%	2,135 ¹	4.5%
Electric Reliability Council of Texas	1,309 ²	2.1%	1,484 ³	2.3%
ISO New England, Inc.	2,183 ²	8.7%	2,116 ⁴	7.8%
Midwest Independent Transmission System Operator	5,300 ²	5.5%	8,663 ⁵	8.0%
New York Independent System Operator	3,291 ²	10.7%	2,498 ⁶	7.5%
PJM Interconnection, LLC	10,454 ²	7.2%	13,306 ⁷	10.5%
Southwest Power Pool, Inc.	1,385 ²	3.5%	1,500 ⁸	3.3%
Total RTO/ISO	27,189	6.1%	31,702	7.0%

Sources:
¹California ISO 2010 Annual Report on Market Issues and Performance
²2010 FERC Survey
³ERCOT Quick Facts (June 2011)
⁴2010 Annual Markets Report, ISO New England Inc.
⁵2010 State of the Market report, Potomac Economics (Midwest ISO)
⁶2010 State of the Market report, Potomac Economics (New York ISO)
⁷PJM Load Response Activity Report, July 2011, "delivery year 2011-2012 active participants"
⁸Informational Status Report Concerning Incorporation of Demand Response In SPP Markets and Planning (September 2, 2011)
⁹Estimated based on peak demand data from the following: California ISO 2010 Annual Report on Market Issues and Performance, 2010 State of the Market Report for the ERCOT Wholesale Electricity Markets, 2010 Assessment of the Electricity Market in New England, 2010 State of the Market Report for the MISO Electricity Markets, New York ISO 2010 State of the Market Report, 2009 State of the Market Report for PJM and 2011 Quarterly State of the Market Report for PJM: January through June, and the Southwest Power Pool 2010 State of the Market.

Extended hot weather and high demand led the Electric Reliability Council of Texas (ERCOT) to activate approximately 1,500 MW of load resources and interruptible resources during a level 2 emergency on August 4, 2011.⁴³ ERCOT invoked another level 2 emergency on August 24, 2011 and deployed interruptible loads.⁴⁴

ERCOT also called on demand response resources in response to severe cold weather during February 2-3, 2011. A significant number of electric generating facilities in the U.S. Southwest tripped off line, failed to start, or had their available capacity de-rated during the extreme cold weather. On February 2, 2011, a cumulative total of 14,702 MW of generation capacity was

⁴³ ERCOT, Press release, "Power Warning - Conservation Critical," August 4, 2011, available at http://www.ercot.com/news/press_releases/show/418.

⁴⁴ ERCOT, Press release, "Update: Emergency procedures cancelled", August 24, 2011, available at http://www.ercot.com/news/press_releases/show/431.

unavailable in the ERCOT region.⁴⁵ The grid operator responded by dispatching demand response, shedding loads and appealing for voluntary energy conservation by the public.⁴⁶

On February 2 more than 1,000 MW of non-controllable load resources responded to the Texas emergency. About 886 MW of load resources responded within 10 minutes of ERCOT's call.⁴⁷ Within the next thirty minutes a scheduling entity contacted ERCOT and shed an additional 140 MW load that was not previously committed.⁴⁸ Several demand response providers reduced more load than was committed.

ERCOT also deployed all of its Emergency Interruptible Load Service (EILS), during the February 2-3, 2011 weather event. ERCOT normally procures EILS three times during the year, but decided to obtain supplemental EILS capacity via a one-time April-May solicitation to ensure the availability of demand response resources for the remainder of the year.⁴⁹

The North American Electric Reliability Corporation (NERC) evaluates demand response resources for reliability purposes. In its 2011 Summer Reliability Assessment, NERC estimated that 35,600 MW of demand response resources would be available during summer 2011. This includes both U.S. and Canadian regions, and is about 5,300 MW more than was available in summer 2010, according to NERC. NERC notes that "the total NERC [demand response] value is only a general indicator or reference for growth in Demand Response resources."⁵⁰ NERC does not consider time-sensitive pricing (e.g., time of use, critical peak pricing) or demand bidding in energy markets in its reliability assessments.

To improve its evaluation of demand response resources, NERC developed a system for regular reporting of demand response to more precisely measure its contribution to reliability. NERC's Demand Response Availability Data System (DADS) collects and analyzes semiannual data from several categories of industry participants.⁵¹ Reporting entities are required to submit information about their individual demand response programs, and each event where demand response was deployed for reliability purposes, during a specified reporting period.

Specifically, DADS collects (1) reporting entity information, (2) demand response program information, (3) contact information, (4) relationship with other programs (e.g., mutually

⁴⁵ Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011*, August 2011, p. 79 ("Southwest Event Report"), available at <http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>.

⁴⁶ *Id.* at 73-79.

⁴⁷ Texas Reliability Entity, Inc., *Protocol and Operating Guide Compliance Report For The February 2, 2011, Energy Emergency Alert Level 3 Event, May 13, 2011*, p. 20, available at http://www.puc.state.tx.us/agency/topic_files/TX_RE_EEA_Protocol_Comp_Report.pdf.

⁴⁸ *Id.*

⁴⁹ ERCOT, *Emergency Interruptible Load Service, Apr-May 2011 Supplemental Contract Period*, available at <http://www.ercot.com/services/programs/load/eils/>.

⁵⁰ NERC, *2011 Summer Reliability Assessment*, May 2011, pp. 10-11.

⁵¹ Balancing Authorities, Distribution Providers, Load-Serving Entities, and Purchasing-Selling Entities that are Registered NERC Entities. See the NERC Reliability Functional Model for more detail (<http://www.nerc.com/page.php?cid=2|247|108>).

exclusive, jointly enrolled), (5) program enrollment data and (6) demand response program performance. Reporting of data by all electricity organizations operating or administering dispatchable and controllable demand response programs (greater than 10 MW and in service for more than one year) is mandatory. DADS will not collect data about non-dispatchable demand, such as time-sensitive pricing. NERC's web-based data collection system began operation on October 4, 2011 and is being used to collect data for the period April through September 2011. NERC will publish the results from DADS beginning in 2012.⁵²

(D) Potential for demand response as a quantifiable, reliable resource for regional planning purposes

The Commission continues to ensure that demand resources are provided comparable treatment. Order No. 1000, issued July 2011, reaffirms Order No. 890's requirement for public utility transmission providers to consider all types of resources, including demand response and energy efficiency, on a comparable basis in transmission planning.⁵³ Order No. 1000 requires the comparable consideration of transmission and non-transmission alternatives in the regional transmission planning process.

Independent of the Commission's actions, a project sponsored by the Department of Energy is also considering demand response as one of the resources evaluated for options to transmission development in the Eastern and Western Interconnections. The Eastern Interconnection plan is being developed under a joint effort by the Eastern Interconnection States' Planning Council (EISPC) representing 39 states, the District of Columbia and eight Canadian provinces, and the Eastern Interconnection Planning Collaborative (EIPC), consisting of 26 regional planning authorities. The first phase of the planning created an interconnectionwide transmission model based on current regional plans. Projections of various resources, including demand response resources, will be developed in the second phase to determine the appropriate combination of resources that will be required to meet load in future years. In July 2011 EISPC (through NARUC) issued a request for proposals for a contractor to evaluate demand-side resources, in part, to support the planning effort. The contractor will evaluate current and projected demand response programs, including price responsive demand and energy efficiency.⁵⁴ The final phase of the Eastern Interconnection effort will model transmission systems to serve the resource scenarios created in the second phase.⁵⁵

The Transmission Expansion Planning Policy Committee (TEPPC, a board committee of the Western Electricity Coordinating Council) oversees the Western Interconnection effort. As part of its study, TEPPC reviewed the effects of increased use of demand response and energy efficiency on the transmission system. For example, the studies for the 2020 time horizon

⁵² NERC, Demand Response Data Task Force Update, June 2, 2011.

⁵³ Order No. 1000, 136 FERC ¶ 61,051 at P 153-154.

⁵⁴ Available at

http://www.naruc.org/SpecialDocs/NARUC%202011%20RFP%20EISPC_DSM%207_11_11.pdf.

⁵⁵ Detailed information available at <http://communities.nrii.org/web/eispc>.

include a high demand side management case in which peak demand, growth of peak demand, and energy consumption are significantly lower than in the base case.⁵⁶

(E) Steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party

The Commission continues to assess and monitor the wholesale electric power markets under its jurisdiction to ensure that demand response resources that are technically capable of providing a service are treated comparably to supply resources. This section summarizes FERC actions taken in the past year for wholesale markets, and also summary descriptions of recent state and industry actions taken at the retail level on demand response programs.

FERC orders on demand response issues

Order No. 745⁵⁷

Order No. 745, issued in March 2011, requires that RTOs and ISOs pay demand response resources participating in the day-ahead and real-time wholesale energy markets the locational marginal price (LMP) when two conditions are met: demand response resources must be capable of balancing supply and demand in the wholesale energy markets, and dispatching and paying LMP to demand response resources must be cost-effective as determined by a net benefits test.

Order No. 745 requires that RTOs and ISOs submit compliance filings to accomplish these changes. RTOs and ISOs are required to include the following elements in their compliance filings:

- A mechanism to identify a monthly price threshold to estimate where the dispatch of demand response resources will be cost-effective resulting in net benefits to organized wholesale energy market customers;
- Tariff changes to allocate the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response;
- A review of the RTO's or ISO's current requirements in light of the changes in Order No. 745 and appropriate revisions and modifications, if necessary, to ensure that their baselines remain accurate and that they can verify that demand response resources have performed. Specifically, the compliance filings must include an explanation of how RTO and ISO measurement and verification (M&V) protocols will continue to ensure that appropriate baselines are set and that demand response will continue to be adequately measured and verified as necessary to ensure the performance of each demand response resource; and

⁵⁶ Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee, *Interim Study Report* (draft) (June 2011).

⁵⁷ Order No. 745, FERC Stats. & Regs. ¶ 31, 322.

- A study examining the requirements for and impacts of implementing a dynamic approach to incorporation of the billing unit effect in the dispatch algorithm, into both the day-ahead and real-time energy markets. Results of the study must be filed with the Commission on or before September 21, 2012.

PJM, California ISO, and Southwest Power Pool filed proposed tariff revisions in compliance with Order No. 745 on July 22, 2011. ISO New England, the New York ISO, and the Midwest ISO submitted Order No. 745 compliance filings on August 19, 2011.

New York ISO's SRC baseline and portfolio aggregation (Docket ER11-2906)

The Commission conditionally accepted New York ISO's proposed amendment to the Services Tariff to apply a new Special Case Resources (SCR) baseline load methodology as well as new performance factor calculations and performance deficiency penalties. Beginning with the winter 2011/2012 capability period, the New York ISO will calculate a demand response resource's baseline utilizing the top 20 hours of the resource's load that are coincident with the top 40 hours of New York ISO peak load during the prior equivalent capability period. Additionally, the tariff amendments include several changes that allow the aggregation of demand response resources.

PJM Interconnection, L.L.C.'s additional product alternatives for demand response (Docket ER11-2288)

In January 2011, the Commission accepted PJM's proposal to establish two additional demand resource products, one available throughout the year for an unlimited number of interruptions (Annual DR), and one available for an unlimited number of interruptions from May through October (Extended Summer DR), in addition to retaining its existing demand resources program. Both the Annual and Extended Summer DR products are available for up to ten hours per interruption. The addition of Annual DR and Extended Summer DR add flexibility to PJM's ability to procure adequate capacity in the Reliability Pricing Model auctions and enhance PJM's emergency dispatch options. The Commission directed PJM to file revised tariff provisions within 30 days to set the methodology for determining the reliability targets for the existing demand response product and the Extended Summer DR product. The Commission accepted PJM's compliance filing in April 2011.

Other FERC demand response activities

Implementation Proposal for the National Action Plan on Demand Response

On July 5, 2011, FERC staff together with the U.S. Department of Energy (DOE) staff sent a comprehensive proposal to implement the National Action Plan on Demand Response (Implementation Plan) to Congress.⁵⁸ As directed by section 529 of EISA, the Implementation Plan reaffirms the need for action identified in last year's National Action Plan and identifies the appropriate roles and leadership required to accomplish action in three areas: technical assistance

⁵⁸ FERC and DOE Staff, *Implementation Proposal for the National Action Plan*, July 5, 2011, available at <http://www.ferc.gov/legal/staff-reports/07-11-dr-action-plan.pdf>.

to states, a national communications program, and the identification or development of tools and materials for use by customers, states, and demand response providers.

A key aspect of the Implementation Proposal is the reliance on non-federal organizations. The lead responsibility for implementing many of the activities has been left primarily to the private sector, ideally through a broad coalition of demand response stakeholders (such as the National Action Plan Coalition), or any private or non-federal governmental organizations that coordinate and cooperate to implement the National Action Plan. The Implementation Proposal also identifies areas where FERC staff and the DOE can leverage existing initiatives and public programs related to demand response to accomplish the actions identified in the National Action Plan.

Retail demand response activities

State governments and regulators developed, and with their utilities implemented, various demand response programs over the past year. These actions included passage of legislation, publication of state energy plans, issuance of regulatory commission decisions, and the deployment of demand response programs and enabling technologies by electric utilities. Some of the results from these activities suggest that there are still barriers to maximizing the demand response resource. A brief summary of recent activities in several states follows.

Retail demand response in Texas

Retail competition is robust in Texas, with an increasing focus on developing demand response products. Over 86 retail providers operate in the Texas retail market, with several utilizing advanced metering and associated infrastructure to provide retail customers with a range of products and services including time of use pricing options.⁵⁹ A web-based portal established by a consortium of transmission and distribution utilities, and managed by ERCOT, facilitates retail access and the development of pricing options by allowing retail electric providers and end-use customers to access, track and manage usage data and meter information.⁶⁰ As a result, retail customers in Texas have the option of self-selecting and switching to time-of-use (TOU) rates, thereby facilitating new demand response product offerings.

Reliant and TXU Energy are two Texas retail electric providers that offer TOU products, which are now supported by advanced metering.⁶¹ Initially, Reliant's residential customers did not understand this TOU product and, as a result, did not subscribe to it. In particular, the customers were reluctant to subscribe to a TOU rate offering that had a large spread in rates between the on- and off-peak periods. The company has since narrowed the spread between the two time

⁵⁹ Public Utility Commission of Texas Chairman Barry T. Smitherman, "Electrical and Telecom Infrastructure Investments...Made in Texas," Texas Workforce Commission: Putting America Back to Work 2011, February 2, 2011, pp. 14, 16.

⁶⁰ Smart Meter Texas, *Frequently Asked Questions*, available at https://www.smartmetertexas.com/CAP/public/home/home_faq.html#a2.

⁶¹ See Energy, Reliant e-Sense® Time-of-Use plan, available at http://www.reliant.com/PublicLinkAction.do?i_chronicle_id=090175228030fcfa&language_code=en_US&i_full_fo_rmat=jsp, and TXU Energy, TXU Energy Time-of-Use, available at <http://www.txu.com/en/residential/promotions/dsm/TOU-savings.aspx>.

periods to gain new customer interest.⁶² The company also provides customers with a weekly summary of electric consumption data, including consumption to date, as well as expected usage forecasts. The TXU Energy demand response program is an example of a demand response program that does not require an advanced metering interface to provide demand response opportunities to the retail sector. Using a web-enabled programmable thermostat, TXU Energy offers a retail product that allows retail customers to manage and control home or business temperatures remotely over the internet or over smart phones.⁶³

In May 2010, Texas enacted legislation to allow demand resources from all retail classes to participate in the wholesale energy market either directly or through aggregators of retail customers. In addition, the legislation directs ERCOT electric utilities to encourage and facilitate the involvement of retail electric providers in the delivery of efficiency programs and demand response programs.⁶⁴ ERCOT is currently evaluating a real-time market upgrade project to enable demand resource participation in ERCOT's real-time energy market and ancillary services market.⁶⁵ Actions taken by the ERCOT ISO may further expand the use of demand response in Texas. According to ERCOT Chair Laura Doll, demand response resources could also participate in the real time energy market and all ancillary service markets in the future.⁶⁶

Other state legislative and regulatory activities related to demand response

Highlights of additional state activities undertaken with respect to demand response programs are provided below. States are examining how demand response programs can support resource adequacy, adopting various policies to support demand response programs, measuring how well utility programs are operating, and analyzing opportunities to expand and deploy additional demand response programs.

- **Connecticut.** In January 2011, Connecticut enacted legislation creating the Department of Energy and Environmental Protection.⁶⁷ Under the new legislation, the Department of Energy and Environmental Protection – rather than the electric companies – will prepare

⁶² Reliant Vice President of Residential Segment Marketing Bill Harmon, Roundtable #6 – Regional Roundup: Focus on Texas, Association for Demand Response & Smart Grid's National Town Meeting on Demand Response and Smart Grid, July 13, 2011.

⁶³ Digi International, "TXU Energy Partners with Digi and Comverge to Launch Nation's First ZigBee-Enabled Demand Response Program over Broadband Internet," June 18, 2008, available at <http://www.digi.com/news/pressrelease?prid=515>.

⁶⁴ Texas Legislature Online, SB 1125 of 2011 Regular Session, available at <http://www.capitol.state.tx.us/BillLookup/History.aspx?LegSess=82R&Bill=SB1125>

⁶⁵ ERCOT, "Load Participation in ERCOT's Security Constrained Economic Dispatch," August 2, 2011 Whitepaper, Demand Side Working Group (DSWG) Meeting, August 9, 2011, available at <http://www.ercot.com/calendar/2011/08/20110809-DSWG>.

⁶⁶ ERCOT Chair for the Board of Directors Laura Doll, "Smart Grids, Texas Style," Association of Women in Water, Energy and Environment, May 19, 2011, p. 22, available at <http://theawip.camp7.org/Resources/Documents/Laura%20Doll.pdf>.

⁶⁷ Connecticut General Assembly, Senate Bill 1243 of 2011 Regular Session, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future, available at http://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=1243&which_year=2011&SUBMIT1.x=0&SUBMIT1.y=0&SUBMIT1=Normal.

an integrated resource plan – using a mix of demand response, energy efficiency programs and power generation. The comprehensive plan will incorporate the state’s efficiency and renewable energy programs.⁶⁸

- **Illinois.** The Illinois Power Agency (IPA), which develops and submits annual electricity procurement plans to the Illinois Commerce Commission (ICC), submitted the third annual 2011 Power Procurement plan in September 2010. In its December 2010 modified approval of the procurement plan, the ICC directed the IPA not to procure demand response or energy efficiency as an energy supply resource.⁶⁹ The ICC concluded that the IPA is not statutorily authorized to seek energy efficiency as a resource. The ICC also concluded that the IPA plan did not provide a sufficient analysis of the cost impacts.
- **Indiana.** In May 2011, Indiana established a voluntary Clean Energy Portfolio Standard, which includes renewables, storage technologies, and demand side management programs, conservation programs, and measures to shift customers' electric loads from periods of higher demand to periods of lower demand.⁷⁰
- **Maryland.** Maryland Public Service Commission staff, which monitors and reports on utility programs, advised in March 2011 that the energy savings and demand reductions for 2010 were “anemic,” with utilities generally performing at approximately a third of their forecasts for 2010. Staff predicted that the state’s utilities would not reach the energy consumption and demand reduction objectives for 2011 included in the EmPower Maryland Act of 2008.⁷¹
- **Missouri.** In February 2011, the Missouri Public Service Commission (Missouri Commission) concluded a formal rulemaking process and issued regulations for demand side management.⁷² In March 2011, the Missouri Commission released a statewide demand side management market potential study assessing the electric and natural gas demand side management potential for the state’s residential, commercial, and industrial sectors. The Missouri study specifically focused on cost-effective energy saving opportunities available from current programs and technologies, and found that the residential and commercial sectors provide the largest sources of potential energy

⁶⁸ Connecticut General Assembly, Office of Legislative References (OLR) Bill Analysis for SB-1243, as amended by Senate "A", available at <http://www.cga.ct.gov/2011/BA/2011SB-01243-R01-BA.htm>.

⁶⁹ Illinois Commerce Commission, Case No. 10-0563: Illinois Power Agency Petition for Approval of Procurement Plan, available at http://www.icc.illinois.gov/e-docket/reports/browse/document_view.asp?id=11119&no=10-0563&did=159790.

⁷⁰ Indiana General Assembly, Senate Act 251 of the 2011 Regular Session, Chapter 37. Voluntary Clean Energy Portfolio Standard Program, available at <http://www.in.gov/legislative/bills/2011/SE/SE0251.1.html>.

⁷¹ Maryland Public Service Commission Staff, *Annual EmPower Maryland Overall Implementation & EM&V Progress Report (Corrected Version)*, Case Nos. 9153, 9154, 9155, 9156, and 9157, 03/25/2011, available at http://webapp.psc.state.md.us/Intranet/casenum/submit_new.cfm?DirPath=C:\Casenum\9100-9199\9154\Item_173\&CaseN=9154\Item_173.

⁷² Missouri Public Service Commission, Final Orders of Rulemaking, February 9, 2011, Case No. EX-2010-0368: In The Matter Of The Consideration And Implementation Of Section 393.1075, The Missouri Energy Efficiency Investment Act, available at <https://www.efis.psc.mo.gov/mpsc/Docket.asp?caseno=Ex-2010-0368>.

efficiency savings, while demand response programs will continue to provide a large source of peak demand savings.⁷³

- **New Jersey.** In June 2011, the New Jersey Energy Master Plan Committee released a draft 2011 Energy Master Plan that includes goals to support innovative technologies, energy efficiency and conservation programs.⁷⁴ New Jersey expects that smart grid technology will be deployed throughout the state. It notes that while “the technology is already widely used in the industrial and commercial sectors, the extension of this technology to the residential level has the potential to contribute to New Jersey’s economic, environmental and reliability objectives.”⁷⁵ Moreover, with the implementation of advanced metering, the Energy Master Plan expects that customers may take advantage of dynamic pricing.⁷⁶ The draft plan notes that the goal of reducing peak demand will require a substantial increase in demand response programs in the state, and any additional demand response endeavors must be evaluated for cost effectiveness.⁷⁷

Industry Retail Demand Response Actions

As part of the Leadership in Energy and Environmental Design (LEED) rating system, the U.S. Green Building Council established a new credit to incent demand response efforts in buildings.⁷⁸ LEED is a third-party green building certification program that recognizes buildings that have undertaken projects such as energy efficiency and on-site renewable energy projects that provide environmental and human health benefits. The LEED rating system offers various certification levels (e.g., certified, silver, gold, platinum) based upon a building’s construction type. LEED certification levels are based upon the number of credits accrued for a project. The LEED demand response credit is designed to act as an incentive for new construction and existing buildings to participate in demand response programs. In part, LEED demand response credits are broken down into types and levels of automated response: manual, semi-automated, and fully automated options. The program credit, at present in the pilot and market feedback phase, is currently slated for a national roll out in 2012.⁷⁹

(F) Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs

While the federal government, the Commission, and state and local governments continue to work on removing regulatory barriers to customer participation in demand response programs, several of the regulatory barriers identified in past annual assessments and in the 2009 National

⁷³ Missouri Public Service Commission, *Missouri Statewide DSM Market Potential Study: Final Report*, prepared by KEMA, Inc. March 4, 2011, rev 4/14/2011, available at <http://psc.mo.gov/electric/missouri-dsm-potential-study>.

⁷⁴ New Jersey Draft Energy Master Plan, June 2011.

⁷⁵ Id. at 121.

⁷⁶ Id. at 23.

⁷⁷ Id. at 105.

⁷⁸ LEEDuser, “Pilot Credit 8: Demand Response,” available at <http://www.leeduser.com/credit/Pilot-Credits/PC8>.

⁷⁹ Peter Weigand et al., “LEED Credits for Demand Response Participation,” Peak Load Management Alliance Spring Conference, Las Vegas, NV, April 12, 2011, available at <http://www.skippingstone.com/PLMA%20pres.pdf>.

Assessment of Demand Response Potential still remain.⁸⁰ Key outstanding barriers along with efforts to resolve the barriers include:

- **Barriers to Third-Party Demand Response.** The use of third-party demand response providers in both wholesale and retail markets continues to grow. As a percentage of total demand response potential, wholesale demand response grew from 35 percent in 2008 to 39 percent in 2010. Similarly, states and local jurisdictions increasingly have turned to third-party demand response providers to provide capacity resources and meet resource adequacy requirements.⁸¹ Nevertheless, barriers remain for third-party demand response providers to aggregate customer demand response and bid demand response into wholesale RTO organized energy, ancillary services and capacity markets. Due to concerns about reliability, disruption of successful utility demand response programs, cost-shifting, inefficient dispatch, and duplication of administrative costs, a number of states and local jurisdictions have either prohibited third-party aggregation of customer demand response into organized RTO or ISO wholesale markets or have ongoing proceedings examining third-party aggregation.⁸²
- **Cost Recovery.** Recovery of the costs of demand response technologies and programs and the payments made to demand response providers continues to be an issue. Significant progress has been made at the state level to develop policies for the recovery of smart grid and demand response technologies, but there are issues such as advanced meter opt-out (i.e., California and Maine) and recovery of cost-overruns.⁸³ The issuance of Order No. 745 in the past year provides clarity on the Commission's policies on the allocation and recovery of demand response payments in organized RTO and ISO energy and ancillary services markets.
- **Measurement and Cost-Effectiveness of Reductions.** As identified in past annual reports, barriers associated with the measurement and cost-effectiveness of demand reductions remain. Nevertheless, efforts to standardize measurement and verification of wholesale demand response are underway. After months of discussions and review, the North American Energy Standards Board's (NAESB) Wholesale Demand Response Work Group developed a set of changes to the Phase I wholesale demand response M&V standards. These changes were approved by NAESB membership on March 21, 2011, and subsequently filed with the Commission.⁸⁴ In addition, two exhaustive analyses of methods to estimate customer baselines prepared by KEMA for PJM and ISO New

⁸⁰ FERC, *A National Assessment of Demand Response Potential*, June 2009, available at <http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf> (National Assessment).

⁸¹ For example, see EnerNOC, "FirstEnergy Pennsylvania Selects EnerNOC Demand Response to Reduce Peak Energy Use" (September 27, 2011) available at <http://www.enernoc.com/press/>.

⁸² For example, see proceedings in Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and Wisconsin.

⁸³ For example, in response to cost overruns experienced by Xcel Energy's SmartGrid City (SGC) project in Boulder, Colorado, the Colorado Public Utility Commission capped recovery of the overruns "until the Company demonstrates to our satisfaction that it has completed the unfinished aspects of the SGC project." See decision at https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=97559&p_session_id=.

⁸⁴ NAESB, available at <http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12653735>.

England identified best practices for baseline calculations.⁸⁵ As discussed earlier, states continue to work on cost-effectiveness as part of their ongoing proceedings, task forces, and metrics development. Nevertheless, as the Implementation Proposal for the National Action Plan on Demand Response (discussed above) identified, additional work on tools to assist in the measurement and determination of cost-effectiveness is needed.

- **Better coordination of Federal-State policies.** Work on developing better coordination of federal and state regulation of demand response continues, with specific actions being taken at the state level to align state retail demand response programs and policies with RTO and ISO wholesale markets.⁸⁶
- **Limited number of customers on time-based rates.** While time-based rates are not necessary for the continued development of additional demand response resources, greater deployment of time-based rates would support the development of new technologies and programs. For example, the 188 GW demand response potential identified in the Full Participation scenario in the 2009 National Assessment relates to the full deployment of time-based rates and enabling technologies.⁸⁷ Nevertheless, the deployment of these rates at the state and local level has been slow. As described above, the introduction of new pricing products in Texas and the implementation of the pricing experiments funded by the Recovery Act⁸⁸ should provide information and experience to support further deployment of time-based rates.

⁸⁵ KEMA, *Analysis and Assessment of Baseline Accuracy*, prepared for ISO-NE, August 4, 2011, and KEMA, *PJM Empirical Analysis of Demand Response Baseline Methods*, prepared for the PJM Markets Implementation Committee, April 20, 2011.

⁸⁶ For example, the Indiana Utility Regulatory Commission (IURC) directed its utilities to file tariff changes to authorize the participation of their retail customers in Midwest ISO demand response offerings through the utility. See, for example, the IURC order on Duke Energy Indiana's programs at https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801533f3.

⁸⁷ National Assessment, p. 27.

⁸⁸ For more information on these customer behavior studies, see http://www.smartgrid.gov/recovery_act/program_impacts/consumer_behavior_studies.



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