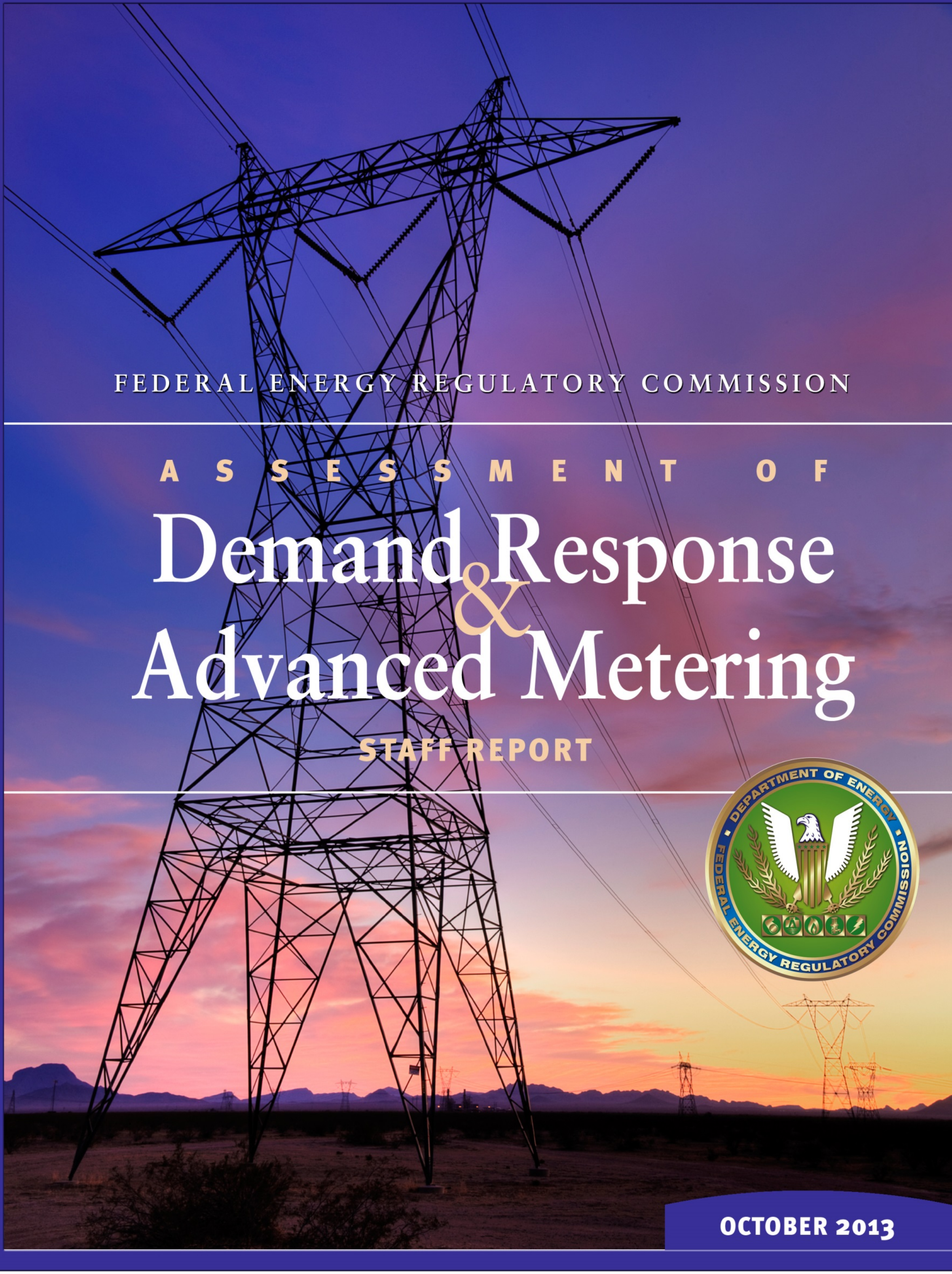

FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF Demand Response & Advanced Metering

STAFF REPORT

OCTOBER 2013

2013

Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

October 2013

ACKNOWLEDGEMENTS

Federal Energy Regulatory Commission Staff Team

Michael P. Lee, Team Lead
Omar Aslam
Ben Foster
David Kathan
Jordan Kwok
Lisa Medearis
Ray Palmer
Pamela Sporborg
Michael Tita

TABLE OF CONTENTS

LIST OF TABLES

FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

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

October 2013

Introduction

This report is the Federal Energy Regulatory Commission staff's (Commission staff's) eighth annual report on demand response and advanced metering. It 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]

Since 2006, Commission staff has published a series of annual reports assessing demand response and advanced metering in the U.S. In support of these reports, the FERC staff has conducted comprehensive nationwide surveys every other year. For reports in intervening years, including this report, the information is based on publicly-available information and discussions with market participants and industry experts.

Based on the information reviewed, it appears that:

- Data from several sources show that the penetration of advanced meters is up, from approximately nine percent in 2009 to nearly 25 percent in late 2011/early 2012;[3]
- Since 2009, demand response potential in organized markets operated by the Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and Electric Reliability Council of Texas (ERCOT) increased by more than 4.1 percent; and,
- Demand response resources made significant contributions to balancing supply and demand during system emergencies for several RTOs and ISOs in the summer of 2013.

[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), http://www.ferc.gov/industries/electric/indus-act/demand-response.asp. The 2007 through 2012 annual reports are also available at http://www.ferc.gov/industries/electric/indus-act/demand-response.asp.

[3] FERC uses the term advanced meter as synonymous with advanced AMI meters (i.e., smart meters). As defined by the EIA, advanced AMI meters have built-in two-way communication capable of recording and transmitting instantaneous data (measured and recorded usage data at minimum, in hourly intervals, provided to both consumers and energy companies at least once daily). *See* EIA, EIA Form-826 and EIA Form-861 Frequently Asked Questions (FAQs), http://www.eia.gov/survey/faqs/electricity.html.

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:

(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 relevant state, federal and industry activities is also provided.

(A) Saturation and penetration rate of advanced meters

Recent data from various sources provide consistent estimates of advanced meter penetration rates. The Energy Information Administration (EIA) reports that in 2011, approximately 37.3 million advanced meters were in use out of 151.7 million meters nationwide, indicating a 24.6 percent penetration rate.[4] The most recent FERC Survey of advanced meters, conducted in 2012 and reported in the 2012 Demand Response and Advanced Metering Report, showed a penetration rate of 22.9 percent.[5] Other sources report similar numbers. For example, data collected by the Institute for Electric Efficiency (IEE) in May 2012 indicate that advanced meters represent approximately 23.5 percent of all meters.[6] More recently, IEE, which has changed its name to Innovation Electricity Efficiency, released an August 2013 report indicating that as of July 2013 almost 46 million smart meters have been installed in the U.S.[7] IEE's recent data implies an advanced meter penetration rate of approximately 30 percent.

Table 1 summarizes the available information on advanced meter installations.

[4] Energy Information Administration, Form EIA-861, 2011 Data File 2 and File 8, http://www.eia.gov/cneaf/electricity/page/eia861.html.

[5] FERC, *2012 Assessment of Demand Response and Advanced Metering: Staff Report*, December 2012, http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf.

[6] Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals*, May 2012, http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterRollouts_0512.pdf. Penetration rate based on 35.7 million installed advanced meters (IEE) and 151.7 million U.S. electric consumers (Energy Information Administration, Form EIA-861 Data, Data File 2, 2011). IEE predicts that if present trends continue, about 65 million advanced meters will be installed nationwide by 2015.

[7] IEE, *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits*, August 2013, http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterUpdate_0813.pdf.

Table 1: Estimates of Advanced Meter Penetration Rates

Source of No. of Advanced Meters	Reference Date (Month/Year)	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rates (advanced meters as a % of total meters)
2008 FERC Survey	Dec 2007	6.7 [1]	144.4 [1]	4.7%
2010 FERC Survey	Dec 2009	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec 2011	38.1 [3]	166.5 [3]	22.9%
EIA-861 Annual Survey	Dec 2011	37.3 [4]	151.7 [4]	24.6%
Institute for Electric Efficiency	May 2012	35.7 [5]	151.7 [4]	23.5%
Innovation Electricity Efficiency	July 2013	45.8 [6]	151.7 [4]	30.2%

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] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2012).
[4] Energy Information Administration, Form EIA-861 Data File 2 and Data File 8 for 2011 (http://www.eia.gov/cneaf/electricity/page/eia861.html).
[5] Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (May 2012).
[6] Innovation Electricity Efficiency, Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits (August 2013).

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 2013. Federal, state and local governmental entities as well as industry stakeholders continue to develop policies and infrastructure to facilitate deployment of advanced metering and address issues concerning its use. What follows are examples of continued programmatic support for advanced meters, demonstrated benefits of advanced meters, and continued public concerns with deployment of advanced meters.

Federal and state programmatic support for advanced meters

Support for the deployment of advanced meters continues at the federal and state levels. The American Recovery and Reinvestment Act of 2009 (Recovery Act)[8] appropriated $4.5 billion to the U.S. Department of Energy (DOE) for grid modernization programs, with $3.4 billion of that amount devoted to the Smart Grid Investment Grant (SGIG) program, a public-private partnership initiative for leveraging investments in grid modernization. As of June 30, 2013, approximately 12.8 million advanced meters were installed and operational using Recovery Act funding of the SGIG program.[9] Ultimately, 15.5 million advanced meters are expected to be installed and operational under SGIG. All SGIG projects are expected to reach completion between 2013 and 2014.

[8] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 (2009).

[9] U.S. Department of Energy, SmartGrid.gov, "Advanced Metering Infrastructure and Customer Systems, Smart Meters Deployed and Operational," http://www.smartgrid.gov/recovery_act/deployment_status. Note responses were provided by 78 entities. SGIG recipients have reported approximately 15.4 million advanced meters physically installed as of June 30, 2013.

Collaborative industry-government efforts

Industry has worked with the National Institute of Standards and Technology (NIST), DOE, state public utility commissions, and organizations such as the North American Energy Standards Board (NAESB) to standardize the types and format of data made available from advanced meters and to use that information to develop new customer services and products. For example, Green Button initiated by NIST, DOE and the White House's Office of Science and Technology Policy (OSTP),[10] is now an industry-led effort to provide electricity customers with secure energy-usage data in a standardized, easy-to-understand format that is accessible from personal computers and mobile devices. A consumer who has a smart meter need only click on a "Green Button" icon at a participating utility's website to download his/her own hourly electricity usage information, typically for up to 13 months.[11] As of May 2013, 27 utilities with operations in 17 states and the District of Columbia have voluntarily committed to participate in the program, and an additional seven utilities have activated programs that allow their customers to securely download their usage data using Green Button.[12] In addition, demand response providers (i.e., curtailment service providers, aggregators or retail customers) can use Green Button data as a verification tool for their demand response programs.[13]

In late 2012, after considerable additional work by utilities and others within the Smart Grid Interoperability Panel (SGIP) framework,[14] SDG&E launched Green Button Connect My Data, which allows customers to automatically send their energy usage data to third-party providers, giving customers additional options to view their previous day's usage data using a smartphone application.[15] In addition, some federal agencies are working to incorporate Green Button data into their programs. For example, the Environmental Protection Agency's (EPA) Home Energy Yardstick tool is now compatible with Green Button data.[16] To help promote the widespread standardization and adoption of Green Button software, NIST established a new Priority Action Plan (PAP) to standardize the testing and certification protocols for utility and vendor Green Button implementations.[17]

The wealth of information produced by advanced meters has spurred the increased development of customer services and products, such as home energy reports, home energy management software, and mobile software applications (*e.g.*, notifications, outage/restoration mapping, usage

---

[10] *See* Green Button, "About Green Button," http://www.greenbuttondata.org/greenabout.html.

[11] *Ibid*. Data are available from the date of smart meter installation up to 13 months, or even longer in some cases.

[12] States currently participating include Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, and West Virginia, as well as the District of Columbia. Green Button, "Adopters," http://www.greenbuttondata.org/greenadopt.html.

[13] NIST webinar, April 2013, http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP20MeetingMinutesAndSlides.

[14] NIST established the Smart Grid Interoperability Panel as a public-private partnership to help manage the development of smart grid interoperability standards in 2010.

[15] SDG&E, "Green Button Connect My Data," http://www.sdge.com/using-green-button-connect-my-data.

[16] Energy Star, "Home Energy Yardstick," https://www.energystar.gov/index.cfm?fuseaction=HOME_ENERGY_YARDSTICK.showGetStarted.

[17] NIST, PAP20 Green Button ESPI Evolution, http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/GreenButtonESPIEvolution.

profiles, billing, and service requests). Certain utilities[18] have partnered with third-party software providers to develop interface applications that simplify and deliver energy consumption data directly to retail customers. For example, monthly energy consumption data reports can alert customers to potential cost-savings from energy efficiency measures, behavioral changes or alternative rate programs.

Demonstrated benefits of advanced meters

Recent storm activity and extreme weather events have provided utilities that have deployed advanced meters with an opportunity to assess the meters' ability to contribute to power system resiliency and help facilitate efficient restoration of electric service following outages caused by storm damage. Electric system outages can be the result of small, medium, and very large scale events spanning several states that often impact other infrastructure systems (*e.g.*, communication, financial, and health care).[19] State regulators and utilities continue to review system hardening and resiliency measures designed to combat and mitigate future storm damage and outages, and the application of new information and communication technologies, including advanced meters, are now a featured component of storm response discussions.[20] Some of the early reports on how advanced meters integrated with other technologies have helped keep the lights on and enabled faster service restorations during recent weather events include the following:

June 2012 "Derecho" and Other Storm Events: During the June 2012 "Derecho" wind storm, advanced meters installed in Atlantic City Electric's New Jersey service territory helped the utility predict the location and extent of the outages, and deploy repair crews to areas where they were most effective.[21] Also in June 2012, Electric Power Board Chattanooga (EPB Chattanooga) employed automated switches working in tandem with advanced meters to reduce the total number of customer power outages by at least half, and avoided 58 million minutes of power disruptions for their customers.[22] EPB Chattanooga was also able to restore power one and a half days sooner than would have been possible prior to the switch and meter upgrades, and the municipality realized $1.4 million in operational savings. Similarly, during a separate storm event in April 2013, Commonwealth Edison reported that the use of automated switches and advanced meters prevented 20,000 service interruptions.[23]

---

[18] Examples include Florida Power & Light, Southern California Edison, and San Diego Gas & Electric.

[19] The GridWise Alliance, *Improving Electric Grid Reliability and Resilience: Lessons Learned from Superstorm Sandy and other Extreme Events*, Workshop Summary and Key Recommendations, June 2013, http://www.gridwise.org/documents/ImprovingElectricGridReliabilityandResilience_6_6_13webFINAL.pdf.

[20] Edison Electric Institute, *Before and After the Storm*, January 2013, pp. 1, 7, 12, http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/Before%20and%20After%20the%20Storm.pdf.

[21] Tom Johnson, "Smart Grid, Meters, No Magic Bullet for Damage Done by Major Storms," NJ Spotlight, http://www.njspotlight.com/stories/12/12/03/smart-grid-meters-no-magic-bullet-for-damage-done-by-major-storms/.

[22] Katherine Tweed, "Smart Grid Saves EPB Chattanooga $1.4M in One Storm," Greentechgrid, October 17, 2012, http://www.greentechmedia.com/articles/read/distribution-automation-saving-epb-millions.

[23] ComEd, "ComEd's 'Smart Switches' Reducing Service Interruptions," April 30, 2013 [Press release], https://www.comed.com/newsroom/news-releases/Pages/newsroomreleases_04302013.pdf.

Hurricane Sandy: In October 2012, after the landing of Hurricane Sandy, Baltimore Gas and Electric (BGE) and Pepco noted that advanced meters assisted with efficient storm restoration, as well as customer outreach efforts, in Maryland and the District of Columbia. BGE was able to dispatch crews more efficiently by quickly identifying areas where power was already restored. Both BGE and Pepco noted that potential communication barriers were avoided by using advanced meter signals, instead of calling residential customers to confirm restoration of electric service.[24],[25]

In November 2012, San Diego Gas & Electric (SDG&E) announced plans to integrate advanced meters with an advanced Outage Management System to track multiple outages during large storms and to better organize planned outages.[26] This will allow SDG&E to reach an outage site prior to customer calls and better manage and monitor power flow and undertake planned outages.[27]

Privacy and other customer concerns

New and emerging technologies can modernize the electric grid, while also providing customers with new tools that engage and meet customer needs. However, concerns about the security and privacy of customer data remain. To this end, policy makers and industry continue to work through NIST and other forums to develop privacy policies and procedures.[28]

Interval usage data from advanced meters in conjunction with other enabling technologies can expand opportunities for demand response and energy efficiency programs. Facilitated by the DOE and the EPA, the State & Local Energy Efficiency Action Network (SEE Action) issued an analysis of state approaches to data access, security and privacy when utilities provide customer data to a third party for energy efficiency programs. California, Colorado, Oklahoma, Oregon, Texas, Vermont, Washington, and Wisconsin have adopted rules governing third-party access to customer data, and seven state commissions have open dockets as of December 2012.[29] The National Association of Regulatory Utility Commissioners (NARUC) released an updated primer concerning, in part, the security of data. The primer addresses cybersecurity for the electric grid

[24] Jeannette M. Mills, "Working to put this storm behind us offers glimpse ahead to smarter grid," November 2012, http://www.bge.com/Blog/archive/tags/Smart%20Grid/default.aspx.

[25] Martin LaMonica, "Smart Meters Help Utility Speed Sandy Restoration," MIT Technology Review, October 31, 2012, http://www.technologyreview.com/view/506711/smart-meters-help-utility-speed-sandy-restoration/.

[26] SDG&E, "SDG&E Launches Advanced Outage Management System To Benefit Region," November 12, 2012 [Press release], http://www.sdge.com/newsroom/press-releases/2012-11-14/sdge-launches-advanced-outage-management-system-benefit-region.

[27] Katherine Tweed, "SDG&E Pushes the Envelope on Cutting Outages," Greentechgrid, November 21, 2012, http://www.greentechmedia.com/articles/read/sdge-pushes-the-envelope-on-cutting-outages.

[28] For example, the SGIP includes a cybersecurity working group with a subgroup to address privacy issues. The SGIP work on privacy can be found at http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/CyberSecurityCTG.

[29] State and Local Energy Efficiency Action Network, *A Regulator's Privacy Guide to Third-Party Data Access for Energy Efficiency*, December 18, 2012, http://www1.eere.energy.gov/seeaction/pdfs/cib_regulator_privacy_guide.pdf.

and provides conceptual cybersecurity basics, the jurisdictional landscape, and best-practices for policymakers' consideration.[30]

To address customer issues with deployment of advanced meters, states continue to develop "opt-out policies", which may include a fee for customers who object to the installation of an advanced meter to actually "opt-out" of having the meter installed. Many utilities have argued that opt-out fees are justified due to costs associated with having a mix of traditional and advanced meters on a utility's system. For example, the Nevada Public Utility Commission ruled in January 2013 that NV Energy may charge opt-out fees for a trial period.[31] The Michigan Public Service Commission also allowed opt-out fees in a May 2013 order approving a Detroit Edison advanced metering residential opt-out program.[32] In contrast to the above, New Hampshire enacted legislation in June 2012 prohibiting electric utilities from installing and maintaining advanced meter gateway devices without the property owner's consent, thereby establishing an opt-in approach for the state.[33]

An Illinois nonprofit consumer advocacy group sued the City of Naperville to prevent advanced meters from being installed due to concerns over privacy, property rights and the health effects of radio frequency waves associated with the meters' wireless technology. However, the U.S. District Court dismissed the complaint, finding that the factual evidence presented on the health effects of radio frequencies was not sufficient to justify cancelling the City of Naperville's advanced metering rollout. The court also found that the City of Naperville's privacy protections—including anonymous customer ID numbers, data aggregation, and a customer bill of rights[34]—were not proven insufficient to protect customers' right to privacy.[35]

Other state legislative and regulatory activity

- **California.** In October 2012, the California Public Utilities Commission (CPUC) directed the state's investor-owned utilities to ensure interoperability between in-home energy monitoring devices and their advanced meters. In conjunction, the CPUC directed

[30] NARUC, *Cybersecurity for State Regulators 2.0*, http://www.naruc.org/grants/Documents/NARUC%20Cybersecurity%20Primer%202.0.pdf.

[31] Public Utilities Commission of Nevada, *Joint Application of the Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy for authority to establish and implement three separate trial non-standard metering option riders pursuant to the Order issued in Docket No. 11-10007*, Docket No. 12-05003, Order on Reconsideration, January 9, 2013, http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2010_THRU_PRESENT/2012-5/22672.pdf.

[32] Michigan Public Service Commission, *In the matter of the application and request of The Detroit Edison Company seeking approval and authority to implement its proposed Advanced Metering Infrastructure Opt Out Program*, Case No. 17053, May 15, 2013, http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=17053.

[33] New Hampshire General Court, Bill Status System, Senate Bill No. 266, *AN ACT prohibiting electric utilities from installing and maintaining smart meter gateway devices without the residential or business property owner's consent*, Enacted June 7, 2012, http://www.gencourt.state.nh.us/bill_status/Bill_docket.aspx?lsr=2999&sy=2012&sortoption=&txtsessionyear=2012&txtbillnumber=SB266.

[34] Naperville Smart Grid Initiative, *Naperville Smart Grid Customer Bill of Rights*, undated, http://www.naperville.il.us/emplibrary/Smart_Grid/NSGI-CBoR-web.pdf.

[35] *Naperville Smart Meter Awareness v. City of Naperville*, Memorandum Opinion and Order, Case No. 1:11-cv-09299, (Illinois Northern District Court, March 22, 2013). Accessed: The Daily Herald, https://www.dailyherald.com/assets/pdf/DA124298323.pdf.

the state's largest utilities to facilitate a competitive, third-party retail market where customers can select from a variety of in-home energy management devices capable of communicating utility-sponsored energy conservation measures and enabling consumers to respond to demand response events.[36]

- **Connecticut.** In February 2013, the Connecticut Department of Energy and Environmental Protection (DEEP) issued the first Comprehensive Energy Strategy for the state as required by Public Act 11-80. Advanced metering technology, facilitated by dynamic pricing policies, is a central component of the report's multi-pronged strategy for achieving sustainable, day-to-day reductions of peak electricity demand.[37]

- **Illinois.** In June 2013, the Illinois Commerce Commission (ICC) approved updated cost-recovery rates for ComEd and Ameren Illinois in conjunction with the advanced meter deployment required by the Energy Infrastructure and Modernization Act (EIMA).[38,39] The ICC action is in response to the May 2013 enactment of Illinois Senate Bill 9,[40] which amended the EIMA[41] to include cost-recovery rates for the law's mandated advanced meter rollout.[42]

- **Kentucky.** In October 2012, the Kentucky Public Service Commission (KPSC) initiated an administrative proceeding to consider the implementation of advanced metering infrastructure (AMI) technologies and time-of-use electricity prices.[43] The proceedings investigate implementation costs, interoperability standards, and societal impacts related to recommendations made in the state's *Smart Grid Roadmap Initiative* issued in June

---

[36] California Public Utilities Commission (CPUC), *Resolution E-4527, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)*, September 27 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K949/28949960.PDF Note the CPUC resolution directs investor-owned utilities to satisfy the intent and requirements of Ordering Paragraph 11 of the CPUC's *Customer Data Access & Privacy Decision, 11-07-056*, Issued July 28 2011, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/140369.pdf.

[37] Connecticut Department of Energy and Environmental Protection, *2013 Connecticut Comprehensive Energy Strategy*, February 19, 2013, http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf.

[38] Illinois Commerce Commission, "ICC Approves New ComEd AMI Schedule for Smart Meters," December 6, 2012 [Press release], http://www.icc.illinois.gov/downloads/public/ComEdAMIorderonrehearingrevise.doc.

[39] Illinois Commerce Commission, "ICC Approves Ameren Illinois Advanced Meter Plan, Schedule," December 7, 2012 [Press release], http://www.icc.illinois.gov/downloads/public/AmerenAMIrehearingedit.doc.

[40] SB 9 was enacted with legislative override of the governor's veto. State of Illinois, 98th General Assembly, Senate Bill 9, http://www.ilga.gov/legislation/BillStatus.asp?DocNum=0009&GAID=12&DocTypeID=SB&LegID=68374&SessionID=85&GA=98&SpecSess=0.

[41] State of Illinois, Energy Infrastructure Modernization Act, Public Act 097-0616, Senate Bill 1652, 97th General Assembly (2011), http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=097-0616.

[42] Rafael Guerrero, "Lawmakers override Quinn on ComEd veto," *Chicago Tribune*, May 23 2013, http://www.chicagotribune.com/news/local/ct-met-illinois-legislature-com-ed-rate-hike-0523-20130523,0,5365404.story.

[43] Kentucky Public Service Commission, *Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, Case No. 2012-00428, October 2012, http://psc.ky.gov/PSCSCF/2012%20cases/2012-00428/20121001_PSC_ORDER.pdf.

2012.[44] The KPSC, in collaboration with a consortium of state utilities, is examining various smart grid technologies and pricing structures that encourage greater energy efficiency.[45] In May 2013, the ongoing Joint Parties Collaborative proposed to issue a report on utility industry recommendations by June 2014.[46]

- **Maine**. By the end of 2012, the Central Maine Power Company, Bangor Hydroelectric, and the Maine Public Service Company had almost completed installation of advanced metering devices, as well as associated communication and data management systems.[47] Concomitant with near full advanced meter deployment, the Maine Public Utilities Commission approved plans for the Central Maine Power Company to initiate a time-of-use pricing program for residential and small commercial customers.[48]

- **Pennsylvania.** In December 2012, the Pennsylvania Public Utility Commission (PAPUC) issued a final order requiring electric utilities to establish a standard electronic format for providing consenting customers and third-parties with direct access to customer data. The PAPUC established the Electric Data Exchange Working Group, comprised of utilities and stakeholders, to oversee development of standards for acquiring interval usage data via a secure web portal. The Working Group is expected to reach consensus on standards for "bill quality" interval data by March 2015.[49] In December 2012, the Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company submitted their advanced meter deployment plans for approval to the PAPUC,[50] as required by Act 129.[51] Beginning in

[44] Kentucky Public Service Commission, *Smart Grids in the Commonwealth of Kentucky: Final Report of the Kentucky Smart Grid Roadmap Initiative*, June 2012, http://energy.ky.gov/generation/Documents/Smart%20Grids%20in%20the%20Commonwealth%20of%20Kentucky.pdf.

[45] Kentucky Public Service Commission, "PSC Opens Case to Look at Smart Grid and Smart Meters," October 2012 [Press release], http://psc.ky.gov/agencies/psc/press/102012/1001_r02.PDF.

[46] Kentucky Public Service Commission, *Joint Comments on the Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, KPUC Case No. 2012-00428, May 2013, http://psc.ky.gov/PSCSCF/2012%20cases/2012-00428/20130520_Joint%20Comments.pdf.

[47] Maine Public Utilities Commission, *2012 Annual Report*, February 2013, http://www.maine.gov/tools/whatsnew/attach.php?id=495712&an=1.

[48] Maine Public Utilities Commission, "MPUC: New Time-Of-Use Prices for CMP Residential and Small Commercial Customers," December 5, 2012, http://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=463166&v=article08.

[49] Pennsylvania Public Utilities Commission, *Smart Meter Procurement and Installation Order*, Docket No. M-2009-2092655, December 2012, http://www.puc.pa.gov/filing_resources/issues_laws_regulations/act_129_information/smart_meter_technology_procurement_and_installation.aspx.

[50] Pennsylvania Public Utilities Commission, *Joint Petition of Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn Power Company*, PPUC Docket No. M-2009-2123950, December 2012, https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/FE%20SMIP%20Deployment%20Plan%20Petition%20-%20Complete.pdf.

[51] Act 129 requires electric utilities to provide access to electronic meter data between customers, designated third parties, and providers of conservation and load management services. Pennsylvania General Assembly, Act 129, 66 Pa. C.S. § 2807(f)(3) (2008), http://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/66/00.028.006.001..HTM.

January 2013, the companies expect to install approximately 98.5 percent of all advanced metering devices by 2019.[52] In January 2013, PECO Energy Company submitted its Phase II Smart Meter Implementation Plan to the PAPUC. PECO expects to have 600,000 advanced metering devices installed by June 2013, with 1.2 million devices installed before 2015 and full deployment achieved by 2019.[53]

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

Commission staff surveyed existing demand response and time-based rate programs in 2012 (see 2012 FERC Demand Response and Advanced Metering Report) and intends to conduct another survey during 2014. In addition, the U.S. Energy Information Administration (EIA) collects specific data for demand-side management programs designed to modify patterns of electricity usage, including the timing and level of electric demand.[54] EIA expects to release 2012 data in October 2013.[55]

In March 2013, NERC released initial Demand Response Availability Data System (DADS) data results through the 2011-2012 winter (October 2, 2011 to March 31, 2012) periods.[56] NERC states that 80 entities reported demand response program data for the 2011 summer reporting period and 74 entities reported for the 2011-2012 winter reporting period. Aggregate data is presented for reporting entities operating in both the U.S. and Canada, and NERC states the total number of reporting entities may grow to over 200 with the completion of subsequent phases of DADS that are designed to include reliability programs and data on economic demand response and time-based pricing programs.[57]

(C) Annual resource contribution of demand resources

The FERC survey of demand resources is undertaken on a biennial basis, as noted above. As a result, Table 2 compares the survey data for calendar year 2011 as reported in the 2012 Demand Response and Advanced Metering Report to separate values for 2012 from Regional Transmission Organization (RTO) and Independent System Operator (ISO) information sources.[58] Based on publicly available sources of information, the potential resource

[52] *See supra* note 50.

[53] Pennsylvania Public Utilities Commission, *PECO Smart Meter Universal Deployment Plan*, PPUC Docket No. M-2009-2123950, January 2013, https://www.peco.com/CustomerService/RatesandPricing/RateInformation/Documents/PDF/New%20Filings/Petition%20-%20PECO%20Phase%20II%20Smart%20Meter%20Plan%20-%20Petition.pdf.

[54] EIA, Form EIA-861 Annual Electric Power Industry Report Instructions, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[55] EIA, Form EIA-861 data files, http://www.eia.gov/electricity/data/eia861/.

[56] *See infra* pp. 4, 17-18. DADS is a system developed by NERC to collect and analyze semi-annual demand response data from several categories of industry participants. Note that NERC states "issues may be identified that require review and modification of the reported data." NERC data is discussed below.

[57] NERC, *2011 Demand Response Availability Report*, March 2013, p. 12, http://www.nerc.com/docs/pc/dadswg/2011%20DADS%20Report.pdf.

[58] Because the data are taken from different sources, caution must be exercised when making direct comparisons between 2011 and 2012 data.

contribution by demand response in U.S. RTO/ISO markets increased by 6.3 percent from 2010 to 2011 to 32,488 MW, but fell in 2012 to 28,303 MW, a year-on-year decrease of 12.9 percent. As a percentage of peak load, demand response potential decreased by 0.7 percentage points from 2011 to 2012. Overall, the demand response resources' potential contribution in U.S. RTO/ISO markets has increased by 4.1 percent since 2009.[59]

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

	2011		2012	
RTO/ISO	Demand Response (MW)	Percent of Peak Demand[9]	Demand Response (MW)	Percent of Peak Demand[9]
California ISO (CAISO)	2,270 [1]	5.0%	2,430 [1]	5.2%
Electric Reliability Council of Texas (ERCOT)	1,570 [2]	2.3%	1,750 [3]	2.6%
ISO New England, Inc. (ISO-NE)	1,231 [2]	4.4%	2,769 [4]	10.7%
Midcontinent Independent System Operator (MISO)	9,529 [2]	9.2%	7,197 [5]	7.3%
New York Independent System Operator (NYISO)	2,247 [2]	6.6%	1,888 [6]	5.8%
PJM Interconnection, LLC (PJM)	14,127 [2]	8.9%	10,825 [7]	7.0%
Southwest Power Pool, Inc. (SPP)	1,514 [2]	3.2%	1,444 [8]	3.1%
Total RTO/ISO	**32,488**	**6.7%**	**28,303**	**6.0%**

Sources:
[1] California ISO 2012 Annual Report on Market Issues and Performance
[2] 2012 Assessment of Demand Response and Advanced Metering, FERC Staff Report
[3] ERCOT Quick Facts (May 2013)
[4] 2012 Assessment of the ISO New England Electric Markets, Potomac Economics
[5] 2012 State of the Market Report for the MISO Electric Markets, Potomac Economics
[6] 2012 State of the Market Report for the New York ISO Markets, Potomac Economics
[7] PJM Load Response Activity Report, July 2012, "Delivery Year 2012-2013 Active Participants in PJM Load Response Program"
[8] SPP Fast Facts (March 1, 2013)
[9] Estimates based on peak demand data from the following: California ISO 2012 Annual Report on Market Issues and Performance; ERCOT 2011 & 2012 State of the Market Reports; 2011 Assessment of the ISO New England Electricity Markets; ISO-NE Net Energy and Peak Load Report (April 2013); 2011 & 2012 State of the Market Reports for the MISO Electricity Markets; 2011 & 2012 State of the Market Reports for the New York ISO Markets; 2011 & 2012 PJM State of the Markets Reports, Vol. 2; SPP 2011 & 2012 State of the Market Reports.

Recognizing that separate data sets are utilized for 2011 and 2012 in Table 2, general results indicate that CAISO, ERCOT, ISO-NE realized increases in demand response, while other RTO markets realized declines. Significant decreases in demand response potential[60] were realized in the PJM markets. According to the market monitor's report for the 2012/2013 delivery year, a marked decrease in clearing prices in PJM's forward capacity auction caused the number of credits for demand response to fall sharply in 2012.[61] The market monitor also concluded that the decrease in demand response potential was influenced by the discontinuation of the Interruptible Load for Reliability program after the 2011/2012 planning year. The decrease in

[59] The megawatts reported here represent the megawatts of demand response "registered" for participation and potential deployment in the relevant markets and programs, e.g., capacity markets, economic- and reliability-based programs.

[60] In general, demand response resource potential is the potential peak reduction attributable to demand response resources participating in a demand response program. Additional information can be obtained from the FERC-731 General Instructions and Information, http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/instructions.pdf.

[61] Monitoring Analytics, LLC, *State of the Market Report for PJM: Volume 2: Detailed Analysis*, March 14, 2013, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml.

registrations in PJM's load management programs was partially offset by an increase in registrations under its economic programs.

Summer 2013 demand response deployments

Demand response resources made significant contributions to balancing supply and demand for several RTOs and ISOs in the summer of 2013. A heat wave in the Eastern United States during the third week of July and in mid-September drove demand for electricity to record levels in some areas.

On July 19, NYISO set a new record for peak demand of 33,955 MW.[62] NYISO activated demand response resources statewide on July 18 and 19, as well as deploying these resources every day throughout the week to relieve historically congested areas of the lower Hudson Valley and southeastern New York.[63] NYISO states it successfully met this record demand through strong performances by demand response, generation and transmission resources, coordination between NYISO and its neighboring regions, and high availability of wind resources.[64]

The high temperatures also resulted in deployment of demand response in PJM. On three days beginning July 15, PJM called long lead time emergency demand response resources for several of its zones. PJM dispatched 652 MW of demand response resources for two consecutive days on July 15 and 16, and dispatched 1,638 MW of demand response resources on July 18. Economic demand response also contributed to the PJM system during the week. The estimated hourly economic demand response reached levels of approximately 250 MW, 400 MW, 870 MW, 630 MW and 625 MW on each day, respectively, from July 15 through July 19.[65] The combination of emergency and economic demand response resources, in addition to other measures, helped PJM address the transmission constraints, high loads, and unplanned generation outages experienced during the week of July 15, 2013.[66]

On September 11, 2013 PJM called on and received approximately 5,949 MW of demand response resources, which represented the largest amount of demand response PJM has ever received. This demand response helped address the imbalance between supply and demand

---

[62] NYISO, "NYISO Meets Record Demand with Balanced Array of Resources," July 22, 2013 [Press release], http://www.nyiso.com/public/webdocs/media_room/press_releases/2013/NYISO%20Meets%20Record%20Demand%20with%20Balanced%20Array%20of%20Resources%20-%2007_22_13%20-%20FINAL.pdf.

[63] NYISO, "Heat Wave Drives Record Electricity Usage in New York," July 19, 2013 [Press release], http://www.nyiso.com/public/webdocs/media_room/press_releases/2013/Heat_Wave_Drives_Record_Electricity_Usage_in_New_York_07192013.pdf.

[64] NYISO, "NYISO Meets Record Demand with Balanced Array of Resources," July 22, 2013 [Press release], http://www.nyiso.com/public/webdocs/media_room/press_releases/2013/NYISO%20Meets%20Record%20Demand%20with%20Balanced%20Array%20of%20Resources%20-%2007_22_13%20-%20FINAL.pdf.

[65] *PJM Estimated Demand Response Activity July 15-19*, 2013, p. 2, http://www.pjm.com/~/media/markets-ops/demand-response/pjm-hot-days-report-for-july-15-july-19-2013.ashx.

[66] PJM, Week of July 15th, 2013: PJM RTO Operations & Markets, Markets and Reliability Committee Meeting, August 29, 2013, p. 2,http://www.pjm.com/~/media/committees-groups/committees/mrc/20130829/20130829-item-13-hot-weather-operations-presentation.ashx

caused by unusually hot weather and local equipment problems which created emergency conditions in four states. Consumer demand for electricity reached a record-setting 144,370 MW on September 10 while, thanks in part to demand response resources, on September 11 the demand on PJM's system was down to 142,071 MW. The September 10 and 11 peak demands reached 90 percent of PJM's past July 18 summer peak demand of 157,509 MW. While PJM was forced to direct local utilities to curtail 150 MW to ensure reliability, PJM credited voluntary demand response resources with playing a vital role in keeping the power grid stable and air conditioners running during the September peaks.[67]

In ISO-NE, demand peaked at 27,359 MW in the late afternoon of July 19. ISO-NE dispatched approximately 200 MW of emergency demand resources that day in response to high temperatures, unexpectedly high demand and unit outages. On July 15 and 18, wholesale prices rose past $200 per MWh, and exceeded $400 per MWh on July 19.[68] In addition to dispatching demand response resources, ISO-NE also made two requests to retail consumers to conserve electricity voluntarily.[69]

In CAISO, high temperatures in early July led CAISO to issue calls for consumers in the northern half of the state to voluntarily reduce their electricity use on July 1-2.[70] Although forecast to hit an all-time high on July 1, peak demand came in significantly under the forecast, which CAISO attributed to the impact of demand response programs and voluntary conservation.[71]

California activities

The CAISO hosted a workshop on May 13, 2013,[72] and later released a whitepaper titled "California ISO Demand Response and Energy Efficiency Roadmap: Making the Most of Green Grid Resources."[73] The demand response and energy efficiency roadmap comprises four parallel and roughly concurrent paths or tracks of activity that run from 2013 through 2020.[74] The four

---

[67] PJM, "PJM Meets High Electricity Demand During Unusual Heat Wave," September 12, 2013 [Press release], http://www.pjm.com/~/media/about-pjm/newsroom/2013-releases/20130912-pjm-meets-high-electricity-demand-during-unusual-heat-wave.ashx.

[68] ISO New England, *Weekly Market Summary, July 15-21, 2013*, http://www.iso-ne.com/markets/mkt_anlys_rpts/wkly_mktops_rpts/2013/we_2013_07_21_weekly.pdf.

[69] ISO New England, "ISO New England Requests Voluntary Electricity Conservation," July 16, 2013 [Press release], http://www.iso-ne.com/nwsiss/pr/2013/iso_new_england_requests_voluntary_electricity_conservation_final.pdf; and "ISO New England Continues Request for Voluntary Electricity Conservation," July 18, 2013 [Press release], http://www.iso-ne.com/nwsiss/pr/2013/iso-ne_continues_request_for_voluntary_conservation_7.18.13.final.pdf.

[70] CAISO, "Northern California-ONLY *Flex Alert* issued by California ISO as heat wave intensifies," June 30, 2013 [Press release], http://www.caiso.com/Documents/FlexAlert-UrgentConservationNeededNow-NorthernCalifornia_July12013.pdf.

[71] CAISO, "Reminder: Day 2 of Flex Alert!" July 2, 2013 [Press release], http://www.caiso.com/Documents/ReminderDay2_FlexAlertJul2_2013.pdf.

[72] California ISO, "Demand Response," Demand response and energy efficiency roadmap workshop, May 13, 2013, http://www.caiso.com/informed/Pages/StakeholderProcesses/DemandResponseInitiative.aspx.

[73] California ISO, *Demand Response and Energy Efficiency Roadmap Draft*, June 12, 2013, http://www.caiso.com/Documents/Draft-ISODemandResponseandEnergyEfficiencyRoadmap.pdf.

[74] *Ibid*.

paths are: the load reshaping path; the resource sufficiency path; the operations path; and the monitoring path. The roadmap highlights the need for inter-agency coordination and specific areas where coordination and communication are necessary to build new market opportunities for demand response and energy efficiency solutions.[75]

On June 17, 2013, the California Energy Commission (CEC) conducted a workshop to gather input on public policies needed to expand the amount of automated demand response resources available to CAISO.[76] At the CEC workshop, the CAISO indicated that the expected increase in solar and wind integration will alter the daytime load profile in the CAISO system as early as 2015. CAISO expects the system will experience a deep daytime load trough with a rapid and significant escalation between 4 p.m. to 8 p.m. CAISO suggested that flexible demand response resources may be needed to address these unpredictable situations.[77]

ERCOT activities

ERCOT launched two new demand response programs aimed at improving the reserve margin during summer peak events. The first program, launched in June 2012 and expanded in December 2012, is the 30-minute Emergency Response Service (ERS) program.[78] This pilot project will allow eligible participants a half hour to respond to ERCOT requests to reduce their electricity use, and is open to individual customers or an aggregated group of consumers who can reduce demand on the ERCOT grid by at least 100 kilowatts.[79] The board authorized ERCOT to procure up to a total of 150 MW for the pilot.

The second pilot, launched in March 2013, is the Weather-Sensitive Emergency Response Service pilot.[80] This pilot is open to electricity customers that can reduce power use by at least 100 kilowatts. Through qualified scheduling entities, participants will be paid based on how much they reduce demand, either in testing or during an actual event.[81] ERCOT can call on resources beginning with the first level of energy emergency alert (EEA 1), when operating reserves drop below 2,300 MW. Most ERCOT demand response programs go into effect during EEA 2 when reserves drop below 1,750 MW.

[75] CAISO intends to work through the California Demand Response Measurement and Evaluation Committee (DRMEC) to clarify and standardize terminology for classifying demand response programs and resources (e.g., load modifying resources and supply resources). The DRMEC, established by the California Public Utilities Commission (CPUC), is comprised of members from the CPUC, the CEC, and a representative from each of the three state investor-owned utilities, and provides oversight of all statewide and non-statewide demand response program evaluations.

[76] CEC, "Lead Commissioner Workshop: Increasing Demand Response Capabilities in California," http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/presentations/.

[77] Heather Sanders, "CEC IEPR Demand Response Workshop," presented at Lead Commissioner Workshop on Increasing Demand Response Capabilities in California, June 17, 2013, http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/presentations/Panel_5/06_Sanders-ISO_presentation_06172013.pdf.

[78] ERCOT, "ERCOT board extends demand response pilot, approves price floor for generators," December 20, 2012 [Press release], http://www.ercot.com/news/press_releases/show/26365.

[79] *Ibid.*

[80] ERCOT, "New pilot program offers incentives to reduce electric use during summer peaks," March 25, 2013 [Press release], http://www.ercot.com/news/press_releases/show/26422.

[81] *Ibid.*

NERC's Demand Response Availability Data System

In March 2013 NERC published early stage DADS results for two time periods: the 2011 summer (April 1, 2011 to September 30, 2011) and the 2011-2012 winter (October 2, 2011 to March 31, 2012) periods.[82] For the U.S. and Canadian entities providing information about demand response programs that are deployed for reliability purposes, NERC reports there were 527 demand response deployments during the summer of 2011. The average number of demand response resources enrolled during the 2011 summer months was 6.46 million resources, on average the combined capacity of these resources was 50,919 MW, and the average sustained response period was 3 hours and 6 minutes.[83] The average number of demand response resources enrolled during the 2011-2012 winter period was 5.34 million resources, on average the combined capacity of these resources was 48,686 MW, and the average sustained response period was 1 hours and 43 minutes.[84]

(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 in jurisdictional transmission planning processes, processing compliance filings in response to Order No. 1000, which reaffirmed Order No. 890's requirement that public utility transmission providers consider all types of resources, including demand response and energy efficiency, on a comparable basis in transmission planning.[85]

As part of the Recovery Act, the DOE awarded funds for collaborative transmission planning efforts in the Western, Eastern and Texas Interconnections, and these efforts are taking demand response into account.[86] Transmission planning studies in the Western, Eastern and Texas Interconnections are conducted by the Western Electricity Coordinating Council (WECC), the Eastern Interconnection Planning Collaborative (EIPC), and the Electric Reliability Council of Texas (ERCOT), respectively. WECC,[87] EIPC,[88] and ERCOT[89] have each undertaken collaborative work efforts that develop long-term electricity supply futures, estimate the

[82] NERC, *2011 Demand Response Availability Report*, March 2013, http://www.nerc.com/docs/pc/dadswg/2011%20DADS%20Report.pdf. *Note*: NERC states "issues may be identified that require review and modification of the reported data."
[83] *Ibid*., p. 12.
[84] *Ibid*., p. 24.
[85] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 153-154 (2011).
[86] DOE, Office of Electricity Delivery and Energy Reliability (OE), "Interconnection Transmission Planning: Awards," http://energy.gov/oe/downloads/interconnection-transmission-planning-awards.
[87] WECC, "Transmission Expansion Plans," http://www.wecc.biz/committees/BOD/TEPPC/Pages/Plans_Home.aspx.
[88] EIPC, "Phase II SSC Meeting Materials," http://www.eipconline.com/Phase_II_SSC_Meetings.html; and " Phase II Resources," http://www.eipconline.com/Phase_II_Resources.html.
[89] ERCOT, *Long-Term System Assessment for the ERCOT Region*, December 2012, http://www.ercot.com/content/news/presentations/2013/2012%20Long%20Term%20System%20Assessment.pdf; *See also* ERCOT Long-Term Study Task Force, *ERCOT LTS Update*, March 2012, http://www.ercot.com/content/committees/other/lts/keydocs/2012/LTS_Update_4_updated.pdf.

associated transmission requirements, and prepare long-term interconnection-wide transmission plans.[90] Smart grid technologies and demand resources are considered as components within a broad range of alternative supply futures.

For example, demand response study case inputs are to be analyzed in WECC's 20-year plan,[91] and the Western Interconnection SPSC has approved the formation of a task force to examine using demand response for integrating variable generation in the West.[92]

In the Eastern Interconnection, NARUC and the Eastern Interconnection States' Planning Council funded an assessment of demand-side resources and their existing and forecasted deployments within the eastern United States.[93] Additionally, the Oak Ridge National Laboratory (ORNL), working in part with the EIPC Stakeholder Steering Committee, modified and updated the Commission's National Assessment of Demand Response (NADR) model to forecast system peak demand by state and census division.[94]

ERCOT, with the assistance of stakeholders, developed a set of three scenarios for use in the long term study of the Texas Interconnection. All three scenarios consider and model demand response resources.[95] One of the three scenarios includes a sensitivity analysis that assumes a technology-specific mandate to expand demand response.[96]

---

[90] DOE, Office of Electricity Delivery and Energy Reliability (OE), "Learn More About Interconnections," http://energy.gov/oe/recovery-act/recovery-act-interconnection-transmission-planning/learn-more-about-interconnections.

[91] State-Provincial Steering Committee (SPSC), "Demand Side Management," http://www.westgov.org/sptsc/site/workgroups/dsmwg.htm.

[92] SPSC, *Memorandum to the Committee on Regional Electric Power Cooperation and the State-Provincial Steering Committee*, October 12, 2012, http://www.westgov.org/wieb/meetings/crepcfall2012/summary.pdf.

[93] Navigant Consulting, Inc, *Assessment of Demand-Side Resources within the Eastern Interconnection*, Prepared for Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, March 2013, https://eispctools.anl.gov/documents.

[94] Baek, Y.S., et. al., *Eastern Interconnection Demand Response Potential* (ORNL/TM-2012/303), November 2012, prepared by ORNL, managed by UT-Battelle, LLC for the U.S. DOE (contract DE-AC05-00OOR22725), http://info.ornl.gov/sites/publications/files/Pub37931.pdf.

[95] The ERCOT LTS Task Force developed three main scenarios: 1) Business as Usual, 2) Drought, and 3) Environmental and sensitivity cases. All three scenarios include demand response resources and a Business as Usual case will be expanded to include new and emerging technologies. *See* ERCOT Long-Term Study Task Force, *ERCOT LTS Update*, March 2012, http://www.ercot.com/content/committees/other/lts/keydocs/2012/LTS_Update_4_updated.pdf.

[96] *Ibid.*

(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

As part of its ongoing effort to remove barriers to entry and ensure a level playing field for all resources that are technically capable of providing a service to have access to wholesale and interstate markets, the Commission has taken a number of actions related to demand response. This section summarizes those actions taken in the past year, other actions taken at the federal level, and recent state and industry actions taken at the retail level on demand response programs.

FERC demand response orders and activities

Order No. 745

In March 2011, the Commission issued Order No. 745 relating to demand response compensation in organized wholesale energy markets.[97] The Commission has accepted filings that PJM and ISO-NE submitted in order to comply with the requirements of the rule.[98] Both MISO and CAISO have filed multiple compliance filings, and the Commission has largely accepted their proposals, establishing limited requirements for further tariff revisions.[99] The Commission issued an initial order on NYISO's Order No. 745 compliance filing in May 2013, requiring NYISO to make further tariff revisions.[100] Rehearing of that order is currently pending before the Commission. Additionally, on August 14, 2013, NYISO submitted a second compliance filing, which is pending before the Commission. SPP also has an Order No. 745 compliance filing before the Commission. The Commission rejected in part SPP's initial compliance filing and required more explanation on the remainder of that filing.[101] In May 2012, SPP submitted a second compliance filing, which is currently pending before the Commission. In January 2013, SPP replied to a request for additional information from Commission staff relating to certain aspects of its second compliance filing.

Order No. 1000

As noted above, Order No. 1000, issued in July 2011, reaffirmed Order No. 890's requirement that public utility transmission providers consider all types of resources, including demand response and energy efficiency, on a comparable basis in transmission planning.[102] In the first

[97] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011), order on reh'g, Order No. 745-A, 137 FERC ¶ 61,215 (2011).

[98] *See PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,256 (2012) and ISO New England Inc., 138 FERC ¶ 61,042 (2012).

[99] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,146 (2013) and *California Independent System Operator Corp.*, 144 FERC ¶ 61,047 (2013).

[100] *New York Independent System Operator, Inc.*, 143 FERC ¶ 61,134 (2013).

[101] *Southwest Power Pool, Inc.*, 138 FERC ¶ 61,041 (2012).

[102] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132, order on reh'g, Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

half of 2013, the Commission issued 15 orders in response to compliance filings addressing the regional transmission planning and cost allocation requirements of Order No. 1000, addressing each transmission planning region's compliance proposals and directing further compliance filings. Currently, the Commission is in the process of receiving further compliance filings, and in some cases rehearing requests, with respect to each of the transmission planning regions. Moreover, the Commission has started to receive separate filings that include proposals for compliance with the interregional requirements of Order No. 1000.

NAESB Demand Response and Energy Efficiency M&V Standards

In February 2013, the Commission issued a final rule (Order No. 676-G) amending its regulations to incorporate by reference NAESB's business practice standards on the measurement and verification of demand response and energy efficiency resources that participate in organized wholesale electricity markets.[103] The NAESB demand response measurement and verification (M&V) standards revised existing NAESB standards by adding specificity to the existing standards in several areas, including meter data reporting, advanced notification, telemetry and meter accuracy. The Final Rule concluded that these revisions to the NAESB demand response M&V standards represented an incremental improvement to the business practices for measuring and verifying demand resource products and services in the organized wholesale electric markets.

The new NAESB M&V standards for energy efficiency provide criteria that will support the measurement and verification of energy efficiency products and services in organized wholesale electric markets. These new standards include four acceptable measurement and verification methodologies that energy efficiency resource providers may use to participate in organized wholesale electricity markets. They also provide criteria for determining which type of baseline to use in various situations, such as the installation of new energy efficient equipment and processes or the replacement of outdated equipment. The standards also contain rules regarding statistical methods used to accurately determine reduction values, specifications for equipment used to perform measurements, and data validation. The Final Rule concluded that these standards will reduce transaction costs and provide an additional opportunity and increased incentive for energy efficiency resources to participate in the wholesale markets established in RTO and ISO regions.

Other federal demand response activities

National Forum on Demand Response

As part of the Implementation Proposal for the National Action Plan on Demand Response,[104] the U.S. Department of Energy (DOE) and FERC sponsored a National Forum on Demand Response. Within the National Forum, DOE and FERC staff worked with state officials, demand response industry representatives, members of a National Action Plan Coalition, and

[103] FERC, *Standards for Business Practices and Communication Protocols for Public Utilities*, Docket No. RM-05-5-020, Order No. 676-G, February 21, 2013, http://www.ferc.gov/whats-new/comm-meet/2013/022113/E-3.pdf.

[104] FERC and DOE, *Implementation Proposal for the National Action Plan on Demand Response*, July 2011, http://www.ferc.gov/legal/staff-reports/07-11-dr-action-plan.pdf.

experts from research organizations to share ideas, examine barriers and explore solutions for advancing demand response. To help answer questions of what remains to be done with demand response, working groups were formed to focus on key demand response technical, programmatic and policy issues. DOE funding supported the efforts in all four areas.

In February 2013, DOE and FERC staff released a series of new reports prepared by National Forum working groups created to address four issues:[105]

- Cost effectiveness
- Measurement and verification
- Program design and implementation
- Tools and methods

DOE Smart Grid Investment Grants

A series of Department of Energy (DOE) reports released in December 2012 confirm the operational and customer service benefits of AMI in select SGIG projects. The DOE's Office of Electricity Deliverability and Energy Reliability reviewed SGIG projects at or near completing AMI integration with: 1) enterprise software (15 of 63 projects),[106] 2) automated capacitor banks (eight of 26 projects),[107] and 3) automated feeder switching (four of 42 projects).[108] Of the 15 SGIG projects with AMI-enterprise software integration reviewed, representing approximately 3.5 million advanced meters, all showed lower meter operation costs, primarily due to reduced labor and vehicle costs related to remote meter reading and automated billing services. Projects with lower customer densities per distribution line-mile observed the largest savings per customer served. Of the eight SGIG projects with automated AMI-capacitor bank integration, initial results indicate the potential of between 1 and 2.5 percent reductions in peak demand. Of the four SGIG projects with automated AMI-feeder switching, all showed a reduction in both the frequency of outages and in the amount of time customers were without power.

DOE Smart Grid Demonstrations

The Smart Grid Demonstration Program (SGDP), operated by DOE, includes nine projects that employ demand response technologies or otherwise enhance demand response.[109] One SGDP project, the Battelle Memorial Institute's Pacific Northwest project, which is being undertaken

---

[105] DOE, "A National Forum on Demand Response: What Remains To Be Done To Achieve Its Potential," http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/state-and-regional-policy-assistanc-7.

[106] DOE, Office of Electricity Deliverability and Energy Reliability, *Operations and Maintenance Savings from Advanced Metering Infrastructure – Initial Results*, Smart Grid Investment Grant Program, December 2012, http://www.smartgrid.gov/sites/default/files/doc/files/AMI_OM_report_final_12-13-2012[1].pdf.

[107] DOE, Office of Electricity Deliverability and Energy Reliability, *Application of Automated Controls for Voltage and Reactive Power Management – Initial Results*, Smart Grid Investment Grant Program, December 2012, http://www.smartgrid.gov/sites/default/files/doc/files/VVO%20Report%20-%20Final.pdf.

[108] DOE, Office of Electricity Deliverability and Energy Reliability, *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results*, Smart Grid Investment Grant Program, December 2012, http://www.smartgrid.gov/sites/default/files/doc/files/Distribution%20Reliability%20Report%20-%20Final.pdf.

[109] SmartGrid.gov, "Smart Grid Demonstration Program," http://www.smartgrid.gov/recovery_act/overview/smart_grid_demonstration_program.

by in five states by 12 utilities with more than 60,000 customers, is in part using new technologies to provide two-way communication between distributed generation, storage, and demand response assets. A second SGDP project, the National Rural Electric Cooperative Association's (NRECA) Enhanced Demand and Distribution Management Regional Demonstration project is implementing new technologies at 27 cooperatives in 11 states with different geographies and climates. The NRECA project will conduct studies in advanced volt/volt-ampere reactive power for total demand, demand response, critical peak pricing, water heater and air conditioning load control, thermal storage, energy usage portal pilots, and consumer in-home energy display pilots. A third SGDP project, NSTAR Electric and Gas Corporation's Automated Meter Reading-Based Dynamic Pricing, will enable residential dynamic pricing [time-of-use (TOU), critical peak rates, and peak time rebates] and two-way direct load control by capturing automated meter reading (AMR) data transmissions and communicating through existing customer-sited broadband connections in conjunction with home area networks.

Wholesale Demand Response Communication Protocols

The Smart Grid Interoperability Panel[110] formed a Priority Action Plan (PAP) 19 working group to develop and enhance data exchange between RTOs and demand response aggregators. The PAP 19 working group completed work on the Wholesale Demand Response Communication Protocol (WDRCP) on September 21, 2012.[111] The WDRCP defines use cases and creates model extensions for the modeling of distributed demand resources,[112] as well as ways to deploy, measure, and evaluate distributed demand resources in wholesale markets. One of the key features of the WDRCP is the direct use of the Requirement Specification for Wholesale Standard DR Signals (published by NAESB) and the International Electrotechnical Commission's (IEC) Common Information Model, a set of standards widely used by utilities and transmission organizations around the world, including North American RTOs/ISOs.

A working group within the IEC's Technical Committee 57, Power System Communications, is considering the WDRCP for possible incorporation into the Common Information Model standards. The WDRCP protocol has been mapped to two leading demand response standards/applications, namely Open Automated Demand Response (OpenADR), a system for utility and third party communications with building automation systems in commercial and industrial buildings, and MultiSpeak, a system of standardized terminology and data objects used in systems integration for smaller utility operations, including many electric cooperatives.

[110] The Smart Grid Interoperability Panel was established by the National Institute of Standards and Technology, which is responsible for coordinating the development of a framework to achieve interoperability of smart grid devices and systems, including protocols and model standards for information management.

[111] *See* NIST Smart Grid Collaboration Wiki for Smart Grid Interoperability Standards, "PAP19: Wholesale Demand Response (DR) Communication Protocol," https://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/PAP19WholesaleDR in the section "PAP19 Artifacts, Output and Next Steps," subsection "Overview."

[112] Modeling is undertaken within the International Electrotechnical Commission's Common Information Model.

DOD & GSA federal efforts

Managing more than 300,000 buildings on some 500 installations, including barracks, data centers, office buildings and hospitals,[113] the Department of Defense (DOD) is the single largest energy consumer in the Nation.[114] Because of its size, the DOD recognizes it can use its own facilities to overcome development and deployment barriers for promising technologies, including demand response and advanced metering infrastructure.[115] DOD environmental research programs foster technological innovations, assist in developing technologies, and accelerate cost-effective technology transitions into commercial markets through collaborative efforts among federal agencies, academia and industry. For example, DOD is demonstrating enhanced demand response program participation for Naval District Washington (NDW), the regional provider of common operating support to Naval installations within a 100-mile radius of the Pentagon. NDW installations encompass more than 4,000 square miles in portions of Maryland, Virginia and the District of Columbia.[116] NDW has invested in advanced meters and meter data systems, and, as a part of its overall energy reduction strategy, plans to integrate its energy management systems and tools to demonstrate the ability to cost-effectively and securely participate in demand response programs.[117] The NDW project will also determine how to transfer the technology and processes to other DOD services.

The U.S. General Services Administration (GSA) owns and leases over 354 million square feet in 9,600 federal buildings,[118] and more than 30 federal agencies depend on the GSA's Energy Division to assist with energy procurement.[119] In 2012, the GSA Energy Division assisted with two separate wholesale demand response transactions for approximately "24 MW of demand response (~8 MW annually over a three year term)" for U.S. Department of Veterans Affairs facilities in NYISO and GSA facilities in PJM.[120]

---

[113] DOD, Strategic Environmental Research and Development Program (SERDP) and Environmental Security Technology Certification Program (ESTCP), "New Installation Energy and Water Technology Demonstrations Announced for FY 2013," December 13, 2012 [Press release], http://www.serdp.org/News-and-Events/News-Announcements/Program-News/New-installation-energy-and-water-technology-demonstrations-announced-for-FY-2013.

[114] DOD, SERDP and ESTCP, "Energy," http://www.serdp.org/Program-Areas/Energy-and-Water/Energy.

[115] Jeffrey Marqusee, "The Contribution of Technology to Sustainable Energy Panel Discussion," presented at the 2013 J.B. and Maurice C. Shapiro Conference: Laying the Foundation for a Sustainable Energy Future: Legal and Policy Challenges, George Washington University Law School, April 11, 1013, http://www.law.gwu.edu/News/2012-2013Events/Pages/LayingtheFoundationforaSustainableEnergyFutureLegalandPolicyChallenges.aspx.

[116] Commander, Navy Installations Command (CNIC), "About Naval District Washington," http://www.cnic.navy.mil/ndw/About/index.htm.

[117] DOD, SERDP and ESTCP, "Demonstrating Enhanced Demand Response Program Participation for Naval District Washington (EW-201343)," http://docs.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/Microgrids-and-Storage/EW-201343/EW-201343/(language)/eng-US.

[118] GSA, "Facilities Management Overview," http://www.gsa.gov/portal/content/104476?utm_source=PBS&utm_medium=print-radio&utm_term=HDR_1_Bldgs_facilities&utm_campaign=shortcuts.

[119] WorldEnergy, "GSA Awards World Energy 5-Year Energy Management Contract," September 8, 2010 [Press release], http://staging.worldenergy.com/news/gsa-awards-world-energy-5-year-energy-management-contract/.

[120] WorldEnergy, "Demand Response Auctions help GSA Generate More Competition and Keep More Revenue from Energy Curtailment Participation," March 1, 2012 [Press release],

Other state legislative and regulatory activities related to demand response

This section highlights several developments in retail demand response and time-based pricing activities since the publication of the previous report. In most cases, the developments reviewed for this report point to a continued expansion of demand response programs at the retail level, including, in some cases, an evolution of recent time-based pricing pilots into full program offerings.

- **Arkansas.** Act 1078 (Regulation of Electric Demand Response Act), approved on April 11, 2013, specifies the authority possessed by the Arkansas Public Service Commission (APSC) to establish the terms and conditions for marketing and selling demand response to retail customers or into wholesale electricity markets. The latter is prohibited unless the APSC determines that doing so is in the public interest. The marketing and selling of demand response by a municipal electric utility or a consolidated municipal utility improvement district is regulated by the local governing body rather than the APSC.[121]

- **California.** There have been several developments related to demand response in California over the past year. As previously noted, the CEC conducted a workshop on June 17, 2013 to gather input on public policies needed to expand the amount of automated demand response resources available to CAISO.[122] Prior to the CEC workshop and in a November 29, 2012 decision, the California Public Utilities Commission (CPUC) resolved certain policy issues related to its proposed Electric Rule No. 24, allowing retail customers to bid demand response resources, on their own or through an aggregator, directly into CAISO's wholesale energy markets.[123]

  The CPUC also issued Decision 12-04-045 on April 30, 2012, directing the state's Demand Response Measurement and Evaluation Committee (DRMEC)[124] to submit a detailed process evaluation plan that lists all demand response programs to be evaluated during 2012-2014, along with an explanation of the necessity of each evaluation.[125] The DRMEC is required to conduct annual statewide studies assessing the load impacts of demand response programs, but no guidance was provided on process evaluations—which assess how effectively programs are designed and delivered—until the issuance of

---

http://www.worldenergy.com/news/demand-response-auctions-help-gsa-generate-more-competition-and-keep-more-revenues/.

[121] State of Arkansas, Regulation of Electric Demand Response Act, SB 795 (2013), http://www.arkleg.state.ar.us/assembly/2013/2013R/Acts/Act1078.pdf.

[122] CEC, "Lead Commissioner Workshop: Increasing Demand Response Capabilities in California," http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/presentations/.

[123] California Public Utilities Commission, *Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols,* Decision 12-11-025, November 29, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M037/K494/37494080.PDF.

[124] The DRMEC is composed of staff from the California Public Utilities Commission, the California Energy Commission, and a representative from each of the investor owned utilities in the state.

[125] Demand Response Measurement and Evaluation Committee, *Process Evaluation Plan, PY 2012-2014*, November 16, 2012, http://www.cpuc.ca.gov/NR/rdonlyres/7222644F-9FE2-44DA-AD27-09D27313AA82/0/DRMECprocessevaluationplan20122014redacted.pdf.

Decision 12-04-045. The process evaluation studies will be available for review by Fall 2014.[126]

In addition, prior to the announced retirement of Southern California Edison's (SCE) San Onofre Nuclear Generating Station (SONGS),[127] the CPUC issued Decision 13-04-017 on April 18, 2013 approving San Diego Gas & Electric's (SDG&E) and SCE's proposed revisions to their existing demand response programs to mitigate the effects of the continuing outage of SONGS Units 2 and 3.[128] Changes to SCE's programs are estimated to amount to an additional 58 MW of load reduction; the incremental impact of changes to SDG&E's programs was not specified.

In May 2012, the CEC approved the latest version of its Title 24 Building Energy Efficiency Standards, which include requirements for automated demand response controls in certain new buildings. The standards are to take effect on January 1, 2014.[129] As defined in Title 24, "demand responsive controls" allow lighting levels in buildings to be automatically reduced in response to a demand response signal from a local utility. The revisions to Title 24 specify that the lighting controls must be able to receive and respond to "at least one standards based messaging protocol."[130]

- **Connecticut.** In its Comprehensive Energy Strategy, released earlier this year, the Connecticut Department of Energy & Environmental Protection (DEEP) recommended "increased participation in [demand response] programs to help control the costs for Connecticut ratepayers and to allow ISO New England greater flexibility in managing the [wholesale electricity] system."[131] Specifically, the strategy recommended that, in addition to increasing the penetration of advanced meters, the state expand time-of-use pricing and other dynamic rate mechanisms to provide customers with financial incentives to shift their electricity use to lower-price periods.

- **Georgia.** Georgia Power has put in place a time-of-use rate specifically for homes with plug-in electric vehicles. The rate is structured with on-peak, off-peak and "super off-

[126] Demand Response Measurement and Evaluation Committee, "The DRMEC Process Evaluation Plan for 2012-2014," Presented at Fall 2012 Workshop on Non-Impact Studies (San Francisco, CA), December 6, 2012, http://www.cpuc.ca.gov/NR/rdonlyres/0D9CE50F-7C12-4ABD-B027-5E7DB6878916/0/20122014ProcessEvaluationPlanPowerPoint.pdf.

[127] SCE, "Powering SoCal," http://www.songscommunity.com/.

[128] California Public Utilities Commission, *Decision Approving Demand Response Program Revisions for Years 2013 through 2014*, Decision 13-04-017, April 18, 2013, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M064/K206/64206104.PDF.

[129] California Energy Commission, "Energy Commission Approves More Efficient Buildings for California's Future," May 31, 2012 [Press release], http://www.energy.ca.gov/releases/2012_releases/2012-05-31_energy_commission_approves_more_efficient_buildings_nr.html.

[130] California Energy Commission, *Proposed 2013 Energy Efficiency Standards: Title 24, Part 6, and Associated Administrative Regulations in Part 1*, p. 182, http://www.energy.ca.gov/2012publications/CEC-400-2012-004/CEC-400-2012-004-15DAY.pdf.

[131] Connecticut Department of Energy and Environmental Protection, *2013 Connecticut Comprehensive Energy Strategy*, February 19, 2013, http://www.ct.gov/deep/lib/deep/energy/cep/2013_ces_final.pdf.

peak" times; the latter provides a significant discount over peak hours during the summer season, and a smaller discount during the rest of the year.[132]

- **Idaho.** Based on the results of its 2013 Integrated Resource Plan, which estimated no peak hour capacity shortages until 2016, Idaho Power filed a petition with the Idaho Public Utilities Commission (IPUC) to temporarily suspend two of its demand response programs. The IPUC approved a settlement stipulation to the petition, which specifies that existing customers will receive a "continuity payment" to encourage them to remain enrolled in the two suspended programs and that no new customers will be enrolled while the suspensions are in effect. The status of the suspended programs will be reconsidered ahead of the 2014 summer season.[133]

- **Illinois.** The Energy Infrastructure Modernization Act requires participating utilities to file proposed tariffs offering optional peak-time rebate programs to their residential customers within 60 days after approval of the utilities' advanced metering plans by the Illinois Commerce Commission (ICC).[134] In a February 2013 Interim Order, the ICC approved ComEd's proposed Peak Time Rebate (PTR) program, conditioned on the utility making slight amendments to the program plan. The Order notes that the PTR program's first curtailment will take place after June 1, 2015.[135] Because Ameren Illinois does not yet have a Commission-approved AMI plan, it does not have a statutory obligation to file a PTR tariff at this time.[136]

- **Maine.** The Maine Public Utilities Commission (MPUC) approved a time-of-use rate for Central Maine Power Company (CMP) for the one-year period beginning March 1, 2013. The optional program is available to residential and small commercial customers, and is delivered by NB Power, which services approximately one-third of CMP's residential and small commercial load.[137] In addition, the MPUC approved the establishment of a pilot program to test the ability of cost-effective "non-transmission alternatives," such as distributed generation, energy efficiency and demand response, to defer or eliminate the need for new transmission while meeting reliability requirements. In its 2012 Annual Report, the Efficiency Maine Trust, the statewide energy efficiency program administrator, noted that the pilot is scheduled to issue a request for proposals

---

[132] Georgia Power, *Electric Service Tariff: Time of Use – Plug-in Electric Vehicle Schedule: 'TOU-PEV-3'*, http://www.georgiapower.com/pricing/files/rates-and-schedules/2.30_tou-pev-3.pdf.

[133] Idaho Public Utilities Commission, *In the Matter of the Application of Idaho Power for Authority to Temporarily Suspend its A/C Cool Credit and Irrigation Peak Rewards Demand Response Programs,* Case No. IPC-E-12-29, Order No. 32776, April 2, 2013, http://www.puc.state.id.us.

[134] State of Illinois, Energy Infrastructure Modernization Act, Public Act 097-0616, Senate Bill 1652, 97th General Assembly (2011), http://www.ilga.gov/legislation/publicacts/fulltext.asp?Name=097-0616.

[135] Illinois Commerce Commission, *Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program*, Interim Order, Docket No. 12-0484, February 21, 2013, http://www.icc.illinois.gov/downloads/public/edocket/341974.pdf.

[136] Illinois Power Agency, *2013 Electricity Procurement Plan*, Docket No. 12-0544, April 5, 2013, http://www.icc.illinois.gov/downloads/public/edocket/345814.pdf.

[137] Maine Public Utilities Commission, *Order Designating Standard Offer Provider and Directing Utility to Enter Entitlement Agreements*, Docket Nos. 2012-00456 and 2012-00409, November 7, 2012, http://www.maine.gov/mpuc/electricity/rfps/standard_offer/sosmall0912/docs/cmporder_smallMar2013.pdf.

for non-transmission alternative resources in September 2013, and that resources are expected to be in operation by July 1, 2014.[138]

- **Maryland**. Baltimore Gas and Electric (BGE) and Delmarva Power and Light (DP&L) both have peak time rebate programs in place that provide a credit for reductions in electricity consumption during critical peak events. This dynamic rate structure is applicable to BGE's residential customers and to DP&L's residential and small commercial customers.[139] In its June 2012 Request for Authorization, Southern Maryland Electric Cooperative (SMECO) suggested that it would offer a time-of-use rate once its advanced meter installation is approved.[140] Utilities in Maryland have a goal of delivering 200 MW of demand response from dynamic pricing programs, in addition to approximately 700 MW from direct load control programs.[141]

  Another factor potentially affecting demand response in the state is the status of the EmPOWER Maryland program. In its recent final report to the state Senate Finance and House Economic Matters Committees about the future of the program,[142] the Maryland Energy Administration (MEA) noted, based on data about the performance of retail demand response programs,[143] that the state is expected to exceed its target of a 15% reduction in per capita peak demand by 2015. MEA recommended that Maryland continue the EmPOWER program, with several significant changes to its structure and energy and demand savings targets. According to MEA, legislation to extend the EmPOWER program is expected to be introduced in 2014.[144]

- **Minnesota**. In November 2012, the Minnesota Public Utilities Commission (MPUC) approved Dakota Electric Association's[145] petition to implement a pilot time-of-use rate for residential electric vehicle charging. The proposed rate is intended to incent

[138] Efficiency Maine Trust, *2012 Annual Report of the Efficiency Maine Trust*, revised February 12, 2013, http://www.efficiencymaine.com/docs/reports/2012-Annual-Report.pdf.

[139] Timmerman, C., "Maryland Smart Grid Update," presented at the 28th Mid-Atlantic Distributed Resources Initiative Working Group meeting, May 7, 2013, http://sites.energetics.com/MADRI/pdfs/may2013/Timmerman.pdf.

[140] SMECO, *Request of Southern Maryland Electric Cooperative, Inc. For Authorization to Proceed With Implementation Of An Advanced Metering Infrastructure System*, Case No. 9294, ML 140535, June 13, 2012, http://webapp.psc.state.md.us/Intranet/Casenum/submit_new.cfm?DirPath=C:\Casenum\9200-9299\9294\Item_1\&CaseN=9294\Item_1.

[141] Timmerman, C., "Maryland Smart Grid Update," presented at the Mid-Atlantic Distributed Resources Initiative Working Group meeting, May 7, 2013, http://sites.energetics.com/MADRI/pdfs/may2013/Timmerman.pdf.

[142] The EmPOWER Maryland program was established in 2008 upon passage of the EmPOWER Maryland Energy Efficiency Act. The legislation set a goal of reducing per capita electricity consumption and peak demand by 15% by 2015. *See* EmPOWER Maryland Energy Efficiency Act of 2008, 2008 Md. Laws Ch. 131, http://mgaleg.maryland.gov/2008rs/chapters_noln/Ch_131_hb0374E.pdf.

[143] The Maryland Energy Administration's assessment of demand response program performance reflects actual savings from programs implemented from 2007 to 2011 and estimated performance of programs approved through 2015.

[144] Maryland Energy Administration, "EmPOWER Planning Webinar," March 15, 2013, http://energy.maryland.gov/empower3/documents/EmPOWERPlanningWebinar2013-03-15.pdf.

[145] The Dakota Electric Association is an electric distribution cooperative.

customers to charge their electric vehicles during off-peak hours.[146] Also in November 2012, the MPUC approved Minnesota Power's petition to implement a residential time-of-day rate pilot. The pilot incorporates mechanisms for providing customers with feedback about their energy consumption at two time scales and also defines critical peak pricing periods. It is part of the utility's broader Smart Grid Advanced Metering Infrastructure Pilot Project partially funded by the U.S. Department of Energy.[147]

- **New York**. In December 2012, Consolidated Edison of New York (ConEd) filed a petition seeking approval of changes to its existing demand response programs. Among other things, the utility sought to replace existing communicating thermostats in homes participating in its direct load control program with new wi-fi enabled communicating thermostats, and to increase the program budget to cover the cost of these installations over a five-year period. In addition, ConEd sought to expand the program by offering new participants a plug-in smart outlet to enable remote customer control of temperature settings.[148] In an April 2013 order, the New York Public Service Commission (NYPSC) approved ConEd's proposed program changes with significant changes. Instead of a wholesale replacement of existing communicating thermostats, the utility is allowed to replace thermostats with new wi-fi enabled versions only upon failure of the existing technology; the associated increase in budget was denied. The NYPSC found that the incorporation of the plug-in outlet technology into the direct load control program was premature. It ordered ConEd to continue refining the technology offering for another two years within its current pilot format.[149]

- **Ohio.** Duke Energy Ohio and AEP Ohio are offering new time-of-use rates to their residential customers. At the end of 2012, Duke Energy Ohio submitted an application for a new pilot time-of-use rate, which the Public Utilities Commission of Ohio approved on February 13, 2013.[150] The pilot will target up to 5,000 homes with an advanced meter

---

[146] Minnesota Public Utilities Commission, *In the Matter of Dakota Electric Association's Petition to Implement an Electric Vehicle Rate*, Order Approving Electric Vehicle Rate As Modified and Requiring Filings, Docket Nos. E-111/M-12-874, November 8, 2012, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C6A25289-F680-4361-9861-ECC11A1DB71A}&documentTitle=201211-80479-01.

[147] Minnesota Public Utilities Commission, *In the Matter of Minnesota Power's Petition for Approval of a Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure ("AMI") Pilot Project*, Docket Nos. E-015/M-12-233, November 30, 2012, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={AB40027B-94DE-49A5-BCA6-883DEDFD7250}&documentTitle=201211-81209-01.

[148] This type of outlet was tested as part of the utility's Residential Small Appliance Pilot Program (RSAP), which ran through the end of 2012. *See* New York Public Service Commission, *Order Adopting Modifications and Tariff Revisions Related to Demand Response Programs*, Case No. 09-E-0115, April 19, 2013, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/A424588D473ED4EF85257687006F3900?OpenDocument.

[149] *Ibid*.

[150] Public Utilities Commission of Ohio, *In the Matter of the Application of Duke Energy Ohio, Inc. for Approval of Pilot Tariff Rate TD 2013*, Case No. 12-3281-EL-ATA, Finding and Order, http://dis.puc.state.oh.us/TiffToPDf/A1001001A13B13B40142J05994.pdf.

installed and that meet certain conditions of baseline consumption.[151] Customers electing to participate have a choice of three-hour blocks on summer and winter weekdays from which to select their preferred on-peak period.[152] AEP Ohio is offering two new time-of-use rates for customers living in its gridSMART Demonstration Project:[153] the "SMART Shift" program offers a single on-peak and off-peak period, while the "SMART Shift Plus" rate incorporates time-of-use and critical peak pricing elements.[154]

- **Pennsylvania.** Under Act 129 of 2008, the Pennsylvania Public Utility Commission (PAPUC) was charged with establishing a state-wide energy efficiency and conservation (EE&C) program. Phase I of the program (2010-13) set a cumulative energy savings target of three percent of weather-adjusted sales, and a peak demand reduction target of 4.5 percent of each utility's 100 highest demand hours.[155] Phase II of the EE&C program established additional cumulative energy savings targets, but not demand reduction targets, because an assessment of the cost-effectiveness of demand response programs was not available at the time the Implementation Order was issued.[156] In May 2013, the Statewide Evaluator released its demand response study, as directed by the PAPUC. The study found that demand response programs were not cost-effective in 2012, due in part to "aggressive reduction targets" and to the stipulation that utilities reduce peak demand during the 100 hours of highest annual demand, which are difficult to predict. The Statewide Evaluator recommended several changes to the Act 129 demand response requirements and program evaluation for potential inclusion in Phase III of the EE&C program, which would begin in June 2016.[157]

  Utilities continue to expand their time-of-use rate offerings for some customers. A time-of-day rate ("hourly pricing") is the default service for large commercial and industrial customers in Pennsylvania, and is an option for medium C&I customers that have an

[151] Schaefer, "Updates on Advanced Metering Infrastructure (AMI): Ohio Deployments," presented at the 28th Mid-Atlantic Distributed Resources Initiative Working Group meeting, May 7, 2013, http://sites.energetics.com/MADRI/pdfs/may2013/Schaefer.pdf.

[152] Duke Energy Ohio, *Rate TD-13: Optional Time-Of-Day Rate For Residential Service With Advanced Metering (Pilot)*, March 11, 2013, http://www.duke-energy.com/pdfs/Sheet.No.121.RATE.TD-13_3-13.pdf.

[153] AEP Ohio, "gridSMART from AEP Ohio," http://www.gridsmartohio.com/.

[154] AEP Ohio, "Smart Meter Incentive Programs: SMART Shift," https://aepohio.com/save/demoproject/SmartShift.aspx; and "Smart Meter Incentive Programs: SMART Shift Plus," https://aepohio.com/save/demoproject/SmartShiftPlus.aspx.

[155] Pennsylvania Public Utilities Commission, *Energy Efficiency and Conservation Program Implementation Order*, Docket No. M-2008-2069887, January 16, 2009, http://www.puc.pa.gov/electric/pdf/Act129/EEC_Implementation_Order.pdf.

[156] Pennsylvania Public Utilities Commission, *Energy Efficiency and Conservation Program Implementation Order*, Docket Nos. M-2012-2289411 and M-2008-2069887, August 2, 2012, http://www.puc.state.pa.us/pcdocs/1186974.doc.

[157] GDS Associates, *Act 129 Demand Response Study: Final Report*, Prepared for Pennsylvania Public Utility Commission, May 16, 2013, http://www.puc.pa.gov/pcdocs/1230512.docx.

advanced meter installed.[158] On June 1, 2015, medium C&I customers with the appropriate meter will also default to hourly pricing service.[159]

- **Rhode Island.** In a February 2012 order, the Rhode Island Public Utilities Commission (RIPUC) approved a National Grid proposal to conduct a "Load Curtailment Pilot" in the Tiverton/Little Compton area from 2012 - 2017.[160] According to National Grid's revised 2012 System Reliability Procurement Plan, the pilot will test whether demand response can manage local distribution capacity requirements during peak periods.[161] The pilot thus fulfills a requirement under the state's revised System Reliability Procurement Standards to identify "potential non-wire alternative solutions that reduce, avoid, or defer" traditional transmission and distribution solutions.[162] Over the course of the pilot, National Grid plans to install wi-fi programmable controllable thermostats and lighting with enhanced demand response ballasts, as well as some direct load control appliance measures in future years.[163]

  In its 2013 System Reliability Procurement Report, National Grid sought approval to enhance the Load Curtailment Pilot by offering higher energy efficiency incentives, providing additional energy efficiency measures that would not otherwise have been offered through statewide programs, and increasing marketing and participation in the pilot. National Grid estimates that the pilot will deliver annual summer demand savings of 161 kW (1,914 kW lifetime) from the residential and C&I sectors, along with annual energy savings of 500 MWh (5,512 MWh lifetime).[164] The RIPUC approved the continuation of the pilot and the proposed changes to marketing, participation and technology updates.[165]

Industry demand response actions

Leadership in Energy and Environmental Design (LEED)

As part of the Leadership in Energy and Environmental Design (LEED) rating system, in 2010 the U.S. Green Building Council (USGBC) began piloting a new credit to incent demand response efforts in new and existing commercial buildings. The demand response credit was

---

[158] Current tariffs are available at http://www.puc.state.pa.us/utility_industry/electricity/rates_tariffs/electric_tariffs.aspx.

[159] Matheson, "MADRI Working Group Pennsylvania Update," presented at the 28th Mid-Atlantic Distributed Resources Initiative Working Group meeting, May 7, 2013, http://sites.energetics.com/MADRI/pdfs/may2013/Matheson.pdf.

[160] Rhode Island Public Utilities Commission, *In Re: Narragansett Electric Company d/b/a National Grid's 2012 System Reliability Plan*, Order 20662, Docket No. 4296, February 29, 2012, http://www.ripuc.org/eventsactions/docket/4296-NGrid-Ord20662(2-29-12).pdf.

[161] National Grid, *2012 System Reliability Plan Report – Supplement*, Docket No. 4296, February 1, 2012, http://www.ripuc.org/eventsactions/docket/4296-NGrid-SRP-Supp2012(%202-1-12).pdf.

[162] *Ibid*.

[163] *Ibid*.

[164] Rhode Island Public Utilities Commission, *2013 System Reliability Procurement Report*, Docket No. 4367, November 2, 2012, http://www.ripuc.org/eventsactions/docket/4367-NGrid-SRP-2013Plan(11-2-12).pdf.

[165] Rhode Island Public Utilities Commission, *Re: Narragansett Electric Company d/b/a National Grid's 2013 System Reliability Procurement Plan*, Order No. 20911, Docket Nos. 4366 and 4367, December 21, 2012, http://www.ripuc.org/eventsactions/docket/4366-4367-NGrid-Ord20911(12-21-12).pdf.

incorporated into the LEED v4 program (the newest update to the rating system) when adopted by USGBC membership on July 2, 2013,[166] and the LEED v4 program will be fully launched in late 2013.[167]

A facility's eligibility for the credit depends on whether there is an existing demand response program in place or not. For newly constructed facilities in areas with an existing program, credit is given based on several conditions: the capability for real-time, fully automated demand response based on external initiation; an intention to participate in the program for several years; and the ability to reduce peak demand by at least 10 percent. For newly constructed facilities in areas without an existing program, the eligibility requirements include: installing infrastructure to take advantage of future demand response programs or dynamic, real-time pricing programs; developing a plan to shed peak demand by at least 10 percent; and expressing an interest in future program participation to the local utility.[168] Existing commercial buildings can also get credit for participation in demand response programs. The requirements are similar to newly constructed buildings, with the additional option of getting credit for having a system in place that can permanently shift load from peak to off-peak hours.[169]

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

The 2009 National Assessment of Demand Response Potential[170] and previous annual reports describe the barriers to customer participation in demand response. The federal government, the Commission, and state and local governments continue to make progress in removing barriers to demand response. Key outstanding barriers and recent actions taken to address these barriers are presented below:

- **Limited Number of Retail Customers on Time-Based Rates.** As noted in past annual reports, greater deployment of time-based rates, while not necessary for the continued development of additional demand response resources, would support the development of new technologies and programs. Projects undertaken by Oklahoma Gas and Electric, Marblehead Municipal Lighting Department and Sioux Valley Energy, and deployed as part of the Recovery Act, are providing new business cases demonstrating that time-based rates can be used to empower consumers and reduce system peak demands.[171] DOE is working closely with these and other recipients of Recovery Act

[166] U.S. Green Building Council, "USGBC's LEED v4 Passes Ballot and Will Launch This Fall," http://www.usgbc.org/articles/usgbc%E2%80%99s-leed-v4-passes-ballot-and-will-launch-fall.

[167] U.S. Green Building Council, "About LEED v4." http://www.usgbc.org/articles/about-leed-v4.

[168] U.S. Green Building Council, "New Construction, v4 draft: Demand response," http://www.usgbc.org/node/2613001?return=/credits/new-construction/v4-draft.

[169] U.S. Green Building Council, "Existing Buildings, v4 draft: Demand response," http://www.usgbc.org/node/2613007?return=/credits/existing-buildings/v4-draft/energy-%26-atmosphere.

[170] FERC, A National Assessment of Demand Response Potential, June 2009, http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[171] DOE, *Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems – Initial Results*, SmarGrid Investment Program, December 2012, http://www.smartgrid.gov/sites/default/files/doc/files/peak_demand_report_final_12-13-2012.pdf.

funding to gain further information and insights, particularly in the areas of customer response to dynamic pricing and enabling technologies.

- **Coordination of Federal and State Policies.** A lack of coordination among policies at the federal and state levels could slow the development of demand response resources. Some states have taken action to coordinate state retail demand response programs and policies with organized wholesale markets so that programs at the retail and wholesale level are complementary. For example, the California Energy Commission conducted a workshop with CPUC staff, CAISO and stakeholders to gather input on public policies needed to expand the amount of automated demand response resources available to CAISO.[172] On the other hand, some states have limited retail customers' demand response participation in wholesale markets.

- **Measurement and Cost-Effectiveness of Reductions**. Previous annual reports have described barriers associated with the measurement and cost-effectiveness of demand reductions. As noted above, the Commission, NAESB, and the National Forum on the National Action Plan on Demand Response undertook steps to address the lack of consistency in the measurement and verification of demand reductions this past year. While providing guidance on measurement and verification methods for market settlement (including design considerations and continuing challenges), the National Forum's Measurement and Verification Working Group identified outstanding issues associated with impact estimations.[173] In addition, the National Forum's Demand Response Cost-Effectiveness Working Group identified a number of additional research topics associated with quantifying program benefits and costs.[174]

- **Lack of Uniform Standards for Communicating Demand Response Pricing, Signals and Usage Information.** Past annual reports have also identified the need for common information models and protocols to promote more efficient transfer of usage and pricing information between parties. Significant progress has been made within the NIST smart grid interoperability framework process with respect to demand response pricing, signals, and usage information. Organizations such as the North American Energy Standards Board, the Organization for Advancement of Structured Information Systems, and the ISO/RTO Council have generated or sponsored work products that offer standardized approaches to retail and wholesale demand response pricing, signals, and usage information. As a result, standards have been written, and some products such as OpenADR 2.0, Smart Energy Profile 2.0, and Green Button are in various stages of

---

[172] California Energy Commission, "Presentations for June 17, 2013 Lead Commissioner Workshop on Increasing Demand Response Capabilities in California," Docket No. 13-IEP-1F, http://www.energy.ca.gov/2013_energypolicy/documents/2013-06-17_workshop/presentations/.

[173] Goldberg, M. and G. K. Agnew, *Measurement and Verification of Demand Response*, February 2013, prepared for the National Forum on the National Action Plan on Demand Response: Measurement and Verification Working Group, http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-mv.pdf.

[174] Woolf, T., E. Malone, L. Schwartz and J. Shenot, *A Framework for Evaluating the Cost-Effectiveness of Demand Response*, February 2013, prepared for the National Forum on the National Action Plan on Demand Response: Cost-effectiveness Working Group, http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-cost-effectiveness.pdf.

adoption for retail and wholesale markets. Other standards, such as those to facilitate two-way power flow to allow plug-in electric vehicles within demand response programs to be used as electric storage and provide ancillary services, will take longer to finalize and perhaps even longer to reach utilities and consumers.

- **Opportunities for Customer Education and Engagement.** Surveys indicate that customer awareness of the smart grid is currently low.[175] The experiences of several utilities demonstrate that successful customer engagement efforts can promote acceptance of smart grid technologies and increase interest in time-based pricing programs.[176] Ongoing research by the Smart Grid Consumer Collaborative is one source for best practices around customer engagement related to the smart grid and time-based pricing programs.[177]

- **Lack of Demand Response Forecasting and Estimation Tools**. The National Action Plan Forum's Estimation Tools and Methods Working Group analyzed and identified gaps between stakeholder's demand response needs (both immediate and anticipated) and the availability of various analytical capabilities, services and tools to meet these demand response needs.[178] The results of their study indicate that existing analytic capabilities and services are sufficient to effectively address many demand response stakeholder needs. However, the Estimation Tools and Methods Working Group identified four areas where further development may be appropriate: (1) End-user settlement tools, (2) load serving entities/electric distribution companies (LSE/EDC) site opportunity assessment tools, (3) LSE/EDC program implementation tools, and (4) LSE/EDC impact assessment tools.

[175] Smart Grid Consumer Collaborative, *2013 State of the Consumer Report*, January 21, 2013, http://smartgridcc.org/wp-content/uploads/2013/01/SoCR-2013_1.24.pdf.

[176] Smart Grid Consumer Collaborative, *Smart Grid Consumer Engagement Success Stories*, http://smartgridcc.org/news-events/research-release-sg-customer-engagement-success-stories. *See also* Smart Grid Consumer Collaborative, *2013 State of the Consumer Report*, January 21, 2013, http://smartgridcc.org/wp-content/uploads/2013/01/SoCR-2013_1.24.pdf.

[177] Consumer engagement is a key topic for the Smart Grid Consumer Collaborative. *See* "Consumer Engagement," http://smartgridcc.org/category/consumer-engagement.

[178] Satchwell, A., C. Goldman, H. Haeri and M. Lesiw, *An Assessment of Analytical Capabilities, Services and Tools for Demand Response*, February 2013, prepared for the National Forum on the National Action Plan on Demand Response: Estimation Tools and Methods Working Group, http://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/napdr-assessment-analytical-tools.pdf.

FEDERAL ENERGY REGULATORY COMMISSION

ASSESSMENT OF

Demand Response & Advanced Metering

2013

888 First Street, N.E.

Washington D.C.

20426

Published October 2013