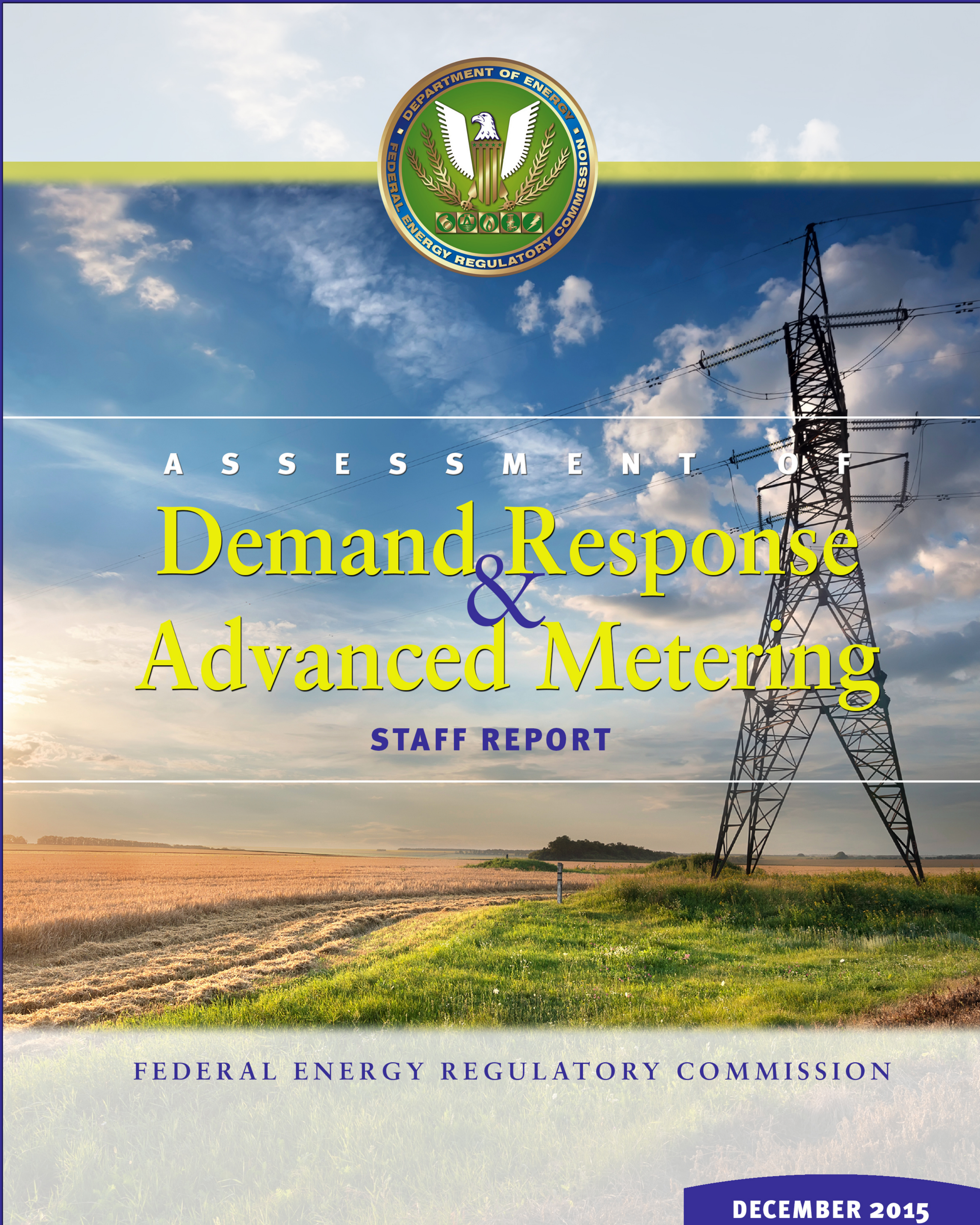

ASSESSMENT OF

Demand Response & Advanced Metering

STAFF REPORT

FEDERAL ENERGY REGULATORY COMMISSION

DECEMBER 2015

2015

Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

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FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

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

December 2015

Chapter 1: Introduction

This report is the Federal Energy Regulatory Commission staff's (FERC or Commission staff's) tenth annual report on demand response and advanced metering required by section 1252(e)(3) of Energy Policy Act of 2005 (EPAct 2005). It is based on publicly-available information and discussions with market participants and industry experts. Based on the information reviewed, it appears that:

- Deployment of advanced meters continues to increase throughout the country.[1] According to the Energy Information Administration (EIA), an additional 8.7 million advanced meters were installed and operational between 2012 and 2013, resulting in advanced meters representing almost 38 percent of all meters in the United States;[2]
- States and various federal agencies continue to undertake significant activities to promote demand response;
- Supported by new policy efforts at the retail level, demand response in conjunction with other established and developing resources and technologies is facilitating innovative grid architectures and system operations; and,
- While demand response barriers continue to be addressed, there is jurisdictional uncertainty associated with the Supreme Court's review of *Electric Power Supply Association v. FERC.*

[1] As defined by the U.S. Energy Information Administration (EIA), Advanced Metering Infrastructure (AMI) Meters are

"Meters that measure and record usage data at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data."

See EIA, Form EIA-861: Annual Electric Power Industry Report Instructions, available at http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[2] EIA, Electric Power sales, revenue, and energy efficiency Form EIA-861 detailed data files, available at http://www.eia.gov/electricity/data/eia861/index.html.

The report addresses 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 (Chapter 2);
(B) existing demand response programs and time-based rate programs (Chapter 5);
(C) the annual resource contribution of demand resources (Chapter 3);
(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes (Chapter 4);
(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 (Chapter 5); and
(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs (Chapter 6).

Chapter 2: Saturation and penetration rate of advanced meters

This chapter reports on penetration rates for advanced meters and developments related to advanced metering through March 2015. As summarized in Table 2-1, recent data indicate that advanced meter penetration rates and the number of advanced meters in operation continue to increase in the United States. This trend is robust across several data sets.

Table 2-1: Estimates of Advanced Meter Penetration Rates

Data Source	Data As Of	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%
2011 Form EIA-861 (re-released)	Dec 2011	37.3 [4]	144.5 [4]	25.8%
Institute for Electric Efficiency	May 2012	35.7 [5]	144.5 [4]	24.7%
2012 Form EIA-861	Dec 2012	43.2 [6]	145.3 [6]	29.7%
Institute for Electric Innovation	July 2013	45.8 [7]	145.3 [6]	31.5%
2013 Form EIA-861 (re-released)	Dec 2013	51.9 [8]	138.1 [8]	37.6%
Institute for Electric Innovation	July 2014	50.1 [9]	138.1 [8]	36.3%

Sources:
[1] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2008).
[2] FERC, Assessment of Demand Response and Advanced Metering staff report (February 2011).
[3] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2012).
[4] U.S. Energy Information Administration (EIA), Form EIA-861 file_2_2011 and file_8_2011 (re-released May 20, 2014). The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. Advanced meters are defined as advanced metering infrastructure (AMI) meters.
[5] The Edison Foundation Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (May 2012).
[6] EIA, Form EIA-861 and Form EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (October 29, 2013). The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. Advanced meters are defined as advanced metering infrastructure (AMI) meters.
[7] The Edison Foundation Institute for Electric Innovation, Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits (August 2013).
[8] EIA, Form EIA-861: Advanced_Meters_2013 data file (re-released June 8, 2015). The number of total meters—including AMI, AMR and standard electromechanical meters—was reported for the first time in 2013. Therefore, we no longer use the number of customers as a proxy. See note 4 above and *Form EIA-861Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, *available at* http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf.
[9] The Edison Foundation Institute for Electric Innovation, Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid (September 2014).

Note: Commission staff has not independently verified the accuracy of EIA or Edison Foundation data. Values from source data are rounded for publication.

According to 2013 data from the Energy Information Administration (EIA),[3] 51.9 million advanced meters were operational nationwide out of a total of 138.1 million meters,[4] indicating a

[3] EIA, Form EIA-861 Advanced_Meters_2013 data file (released June 8, 2015).

37.6 percent penetration rate. Notably, in 2013, the number of two-way smart (AMI) meters surpassed the number of one-way (AMR) meters for the first time.[5] This represents significant growth over the previous year, when EIA reported that 43.2 million advanced meters were operational out of a total of 145.3 million customers, representing a 29.7 percent penetration rate.[6]

Table 2-2 below provides estimated advanced metering penetration rates by North American Electric Reliability Council (NERC) region[7] and retail customer class. Advanced meters represent more than half of the meters in three regions: 79.1 percent of meters in Texas Reliability Entity (TRE), 61.5 percent in Western Electricity Coordinating Council (WECC), and 59.6 percent in Florida Reliability Coordinating Council (FRCC). The largest growth in advanced meter penetration from 2012 to 2013 took place in ReliabilityFirst Corporation (RFC) and Hawaii, which saw increases of 24 and 23.3 percentage points, respectively.

Table 2-2: Estimated Advanced Meter Penetration by Region and Customer Class (2013)

	Customer Class			
NERC Region	Residential	Commercial	Industrial	All Classes
AK	5.2%	2.3%	0.0%	4.8%
FRCC	59.3%	63.2%	80.2%	59.6%
HI	22.5%	28.7%	57.5%	23.3%
MRO	18.0%	14.7%	19.9%	17.7%
NPCC	10.8%	13.7%	23.2%	11.1%
RFC	24.8%	18.0%	16.1%	24.0%
SERC	26.9%	24.0%	20.7%	26.5%
SPP	34.8%	35.8%	41.4%	35.1%
TRE	79.0%	81.4%	48.1%	79.1%
WECC	61.7%	60.4%	52.0%	61.5%
Unspecified	15.7%	17.5%	70.2%	17.0%
All Regions	**37.8%**	**36.1%**	**35.2%**	**37.6%**

Sources: EIA, 2013 Form EIA-861 Advanced_Meters_2013 data file.

Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. The "unspecified" category represents respondents to the EIA-861 short form, which were not required to report a NERC region. Commission staff has not independently verified the accuracy of EIA data.

[4] In 2013, EIA began collecting data on the total number of meters in operation for the first time. In past staff reports, Commission staff relied on EIA data for the total number of customers as a proxy for the total number of meters.

[5] EIA, "Electricity Monthly Update", *available at* http://www.eia.gov/electricity/monthly/update/archive/april2015/.

[6] EIA, Form EIA-861 advanced_meters_2012 data file.

[7] NERC comprises eight regional entities in the lower 48 states: the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool RE (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC). The states of Alaska (AK) and Hawaii (HI) are not subject to NERC oversight.

Overall, Table 2-2, above indicates a slightly higher percentage of residential customers have an advanced meter (37.8 percent) than do customers in the commercial (36.1 percent) or industrial (35.2 percent) customer classes.

Developments and issues in advanced metering

As indicated above, deployment of advanced meters continues to progress throughout the nation's electric system, providing support for two-way communications networks that utilities can use to improve electric system operations, enable new technological platforms and devices, and facilitate consumer engagement. Presented below are examples of continued programmatic support for advanced meters, including collaborative industry-government efforts, and state-level legislative and regulatory activities.

Federal programmatic support for advanced meters

As of March 31, 2015, approximately 16.3 million advanced meters were installed and operational through the U.S. Department of Energy (DOE) Smart Grid Investment Grant (SGIG) program.[8] DOE and the electric industry invested more than $7.9 billion in SGIG projects between 2009 and 2015 to accelerate deployment of smart grid technologies and systems, strengthen cybersecurity, improve interoperability, and collect data on smart grid operations, benefits, and utility impacts.[9] SGIG projects continue to provide grid impact and technological performance reports through 2016.[10]

Collaborative industry-government efforts

The National Institute of Standards and Technology (NIST) published its NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0, in October 2014.[11] NIST coordinates the development of a framework to achieve interoperability of smart grid devices and systems, and the third version of the standards was released in response to the implementation of significant technological advances in smart grid infrastructure, including "widespread deployment of wireless communication power meters, availability of customer energy usage data through the Green Button initiative, remote sensing for determining real-time transmission and distribution status, and protocols for electric vehicle charging."[12] In September 2014, NIST published a revision to its Guidelines for Smart Grid Cybersecurity to describe the relationship of smart grid cybersecurity to the NIST cybersecurity framework, cyber-physical attacks, cybersecurity testing and certification, and to address regulatory changes involving privacy.[13]

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[8] U.S. Department of Energy (DOE), SmartGrid.gov, Deployment Status: Advanced Metering Infrastructure and Customer Systems, *available at* https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems. SGIG recipients reported approximately 16.8 million advanced meters physically installed as of November 30, 2014.

[9] DOE, *2014 Smart Grid System Report* at 3, (Aug. 2014); U.S. DOE.

[10] DOE, Smartgrid.gov Overview, *available at* https://www.smartgrid.gov/recovery_act/overview.

[11] NIST, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0 (1108r3), *available at* http://www.nist.gov/smartgrid/upload/NIST-SP-1108r3.pdf.

[12] *Id.* at 1.

[13] NIST, Guidelines for Smart Grid Cybersecurity (7628 Rev 1), *available at* http://www.nist.gov/manuscript-publication-search.cfm?pub_id=916068.

Separately, the Grid 3.0 planning project was launched as a partnership of six government and industry organizations: the Department of Energy, the Electric Power Research Institute, the GridWise Architecture Council, the National Electrical Manufacturers Association, NIST, and the Smart Grid Interoperability Panel.[14] On November 13, 2014, stakeholders from utilities, ISOs/RTOs, state regulators, federal agencies, manufacturers and researchers met to discuss critical issues facing the electricity sector and the interoperability-related challenges associated with these issues.[15] Participants identified interoperability challenges including resilience, reliability (including efficiency and sustainability), emerging and evolving markets, new actors in the grid ecosystem, and challenges associated with the pace of technology innovation.[16] A two-day Grid 3.0 workshop held March 26-27, 2015 discussed interoperability challenges and developed action plans to overcome the interoperability challenges. Also, the Quadrennial Energy Review has called for the development and adoption of an open standard that will accommodate the continued use of proprietary communication standards.[17]

State legislative and regulatory activity

State governments, retail rate regulators, and individual utilities took various actions in support of advanced metering in the past year. These actions include phasing out and replacing existing meters with advanced meters, studying the potential health effects of exposure to radio frequencies emitted from advanced meters, adjusting or reviewing tariff rates associated with retail customers opting out of advanced meters, and continuing to deploy and completing service territory rollouts of advanced meters.

- **Arizona.** In November 2014, the Arizona Corporation Commission (ACC) received a requested report from the Arizona Department of Health Services (ADHS) studying the potential health effects of exposure to radio frequencies emitted from advanced meters.[18] The ADHS study confirmed that the meters tested were operating within the Federal Communications Commission standard, and exposure to advanced meters is not likely to harm the health of the public.

  In April 2015, the ACC rescinded an earlier decision approving an Arizona Public Service (APS) rate schedule that set opt-out service rates for consumers receiving an

[14] NIST, Electricity Sector Issues Roundtable: Grid 3.0 and Beyond, *available at* http://www.nist.gov/cps/electricity-sector-issues-roundtable.cfm.

[15] *Id.*, "SGIP and Partners Launch Roadmapping Effort for Grid 3.0," The Conductor: News & Activities of SGIP, Vol. 12, December 2012, *available at* http://sgip.org/SGIP/files/ccLibraryFiles/Filename/000000001592/SGIP_News_December.pdf.

[16] Grid 3.0 Workshop, *available at* https://www.pointview.com/e/983.

[17] DOE, Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure, April 2015, p. S-14, *available at* http://energy.gov/sites/prod/files/2015/05/f22/QER%20Full%20Report_0.pdf.

[18] *The Generic Docket for the Commission's Inquiry Into Smart Meters*, Docket No. E-00000C-11-0328, "Public Health Evaluation of Radio Frequency Exposure from Electronic Meters" authored by the Arizona Department of Health, Office of Environmental Health, Arizona Corporation Commission (Nov. 4, 2014), a*vailable at* http://images.edocket.azcc.gov/docketpdf/0000157691.pdf.

analog meter rather than an advanced meter,[19] and determined the issue would benefit from a comprehensive review to be conducted in APS's next general rate case.[20] In the interim, APS is to provide analog meters to customers making such a request, track the unrecovered costs associated with providing analog meters, and may request recovery of any reasonable and prudent unrecovered costs in its next rate case.

- **California.** In January 2015, the California Public Utilities Commission (CPUC) released its 2014 Smart Grid Report.[21] The report notes that the state's three investor-owned utilities (Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE)) have completed their rollouts of advanced meters and, as a result, installed approximately 12 million advanced meters. As of October 2014, PG&E deployed 5.4 million advanced meters; SDG&E, 1.4 million, and SCE, 5 million. The report notes that customers are allowed to opt-out of receiving an advanced meter, and the percentage of customers opting-out remains relatively small.

- **Connecticut.** The Connecticut Department of Energy and Environmental Protection (DEEP) released its most recent biennial Integrated Resource Plan (IRP) for the Commonwealth on March 17, 2015.[22] Among the IRP proposals, DEEP proposes to undertake a proceeding that includes distributed energy resources and, to aid customers, an investigation of technologies such as smart meters and appliances, as well as time-of-use (TOU) and dynamic pricing options.[23] The IRP also assesses energy security, storm resiliency, and new technologies, including advanced meters and the associated infrastructure.[24] DEEP will also require Eversource, Connecticut's largest electric utility, to enter into discussions to phase out and replace existing meters with advanced meters.[25]

- **Florida.** In a January 2015 order,[26] the Florida Public Service Commission (PSC) reduced Florida Power & Light (FPL) tariff rates associated with retail customers opting out of advanced meters. The Florida PSC approved a reduction in the one-time customer enrollment fee from $95 to $89. FPL customers who paid the original $95 enrollment fee

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[19] In the Matter of the Application of Arizona Public Service Company for Approval of Automated Meter Opt-Out Service Schedule 17, Decision No. 75047, Docket No. E-01345A-13-0069, Arizona Corporation Commission (Apr. 30, 2015), available at http://images.edocket.azcc.gov/docketpdf/0000160782.pdf.

[20] *Id.* at PP 16-17.

[21] California Public Utilities Commission, Annual Report to the Governor and Legislature, California Smart Grid per Senate Bill 17 (Padilla, 2009), January 2015, *available at* http://www.cpuc.ca.gov/NR/rdonlyres/09D2DFD4-5ADB-4E25-A165-04CFF9CF0805/0/PGESmartGridAnnualReport_100113.pdf.

[22] Connecticut Department of Energy and Environmental Protection, Integrated Resource Plan, *available at* http://www.ct.gov/deep/cwp/view.asp?a=4405&q=486946&deepNav_GID=2121%20.

[23] *Id.* at 116.

[24] *Id.* at Appendix G, *available at* http://www.ct.gov/deep/lib/deep/energy/irp/2014appendices/ctirp_2014_appendix_g_(energy_security).pdf.

[25] *Id.* at H-21.

[26] *Petition for approval of optional nonstandard meter rider, by Florida Power & Light Company*, Docket No. 130223_EI, Order No. PSC-15-0026-FOF-EI, Florida Public Service Commission (January 2, 1015), *available at* http://www.floridapsc.com/library/Orders/15/00126-15.pdf#search=130223-EI

for an analog meter will receive a bill credit. The monthly surcharge of $13 remains the same for FPL customers selecting the service.

- **Illinois.** In June 2015, Illinois extended the deadline set forth in the 2011 Energy Infrastructure and Modernization Act (EIMA),[27] which provides a performance-based rate tariff for utilities investing in grid modernization components to pursue cost-recovery at the Illinois Commerce Commission (ICC).[28] Under the new eligibility deadline, qualifying utilities have until December 31, 2019 to file for service delivery cost-recovery, retroactive adjustments, and rate reconciliations associated with the installation of advanced meters and the associated infrastructure. Two of the state's largest utilities, Ameren Illinois and Commonwealth Edison (ComEd) state they exceeded their most recent advanced meter deployment objectives. By the end of 2015, Ameren Illinois targets a cumulative deployment of 188,419 advanced meters,[29] and ComEd targets a deployment of 984,617 advanced meters.[30]

  On July 7, 2015, the United States District Court for the Northern District of Illinois dismissed with prejudice and denied leave to amend a third Complaint for Injunctive Relief filed by Naperville Smart Meter Awareness (NSMA), a not-for-profit corporation, against the City of Naperville, Illinois.[31] Since 2013, NSMA has filed four motions alleging that plausible collections of electric usage data by the city through advanced meters infringed on their protection from unreasonable searches under the Fourth Amendment and their right to privacy under the Illinois Constitution. As with their previous motions, the Court dismissed the Third Amended Complaint on the basis that disaggregated interval data of residential electricity usage is neither recorded by the City of Naperville,[32] nor entitled to Fourth Amendment protections.[33] Naperville fully deployed 58,579 advanced meters in fiscal year 2014.[34] For an initial one-time and ongoing monthly fee that represents the labor and equipment costs associated with

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

[28] State of Illinois, Amending Section 5, at 16-108.5, of the Public Utilities Act (Enacted June 1, 2015), House Bill 3975, 98th General Assembly, *available at* http://www.ilga.gov/legislation/BillStatus.asp?DocNum=3975&GAID=12&DocTypeID=HB&LegId=77888&SessionID=85.

[29] Ameren Illinois Company, Advanced Metering Infrastructure ICC Update (April 1, 2015), p. 16 available at http://www.icc.illinois.gov/downloads/public/2015%20AIC%20AMI%20Plan%20Update.pdf.

[30] Commonwealth Edison Company, Smart Grid Advanced Metering Annual Implementation Progress Report (April 1, 2015), p. 35, *available at* http://www.icc.illinois.gov/downloads/public/2015%20AIPR.pdf.

[31] The NSMA also filed a motion for injunction ordering the City to provide analog and non-wireless meters without attendant fees; the City did not oppose the motion. *Naperville Smart Meter Awareness v. City of Naperville*, 11-C-9299 (N.D. Ill. Jul. 7, 2015) available at http://www.gpo.gov/fdsys/pkg/USCOURTS-ilnd-1_11-cv-09299/pdf/USCOURTS-ilnd-1_11-cv-09299-2.pdf.

[32] *Naperville Smart Meter Awareness v. City of Naperville*, 11-C-9299 (N.D. Ill. Mar. 22, 2013) available at http://www.gpo.gov/fdsys/pkg/USCOURTS-ilnd-1_11-cv-09299/pdf/USCOURTS-ilnd-1_11-cv-09299-0.pdf.

[33] *Naperville Smart Meter Awareness v. City of Naperville*, 11-C-9299 (N.D. Ill. Sep. 25, 2014) available at http://www.gpo.gov/fdsys/pkg/USCOURTS-ilnd-1_11-cv-09299/pdf/USCOURTS-ilnd-1_11-cv-09299-1.pdf.

[34] City of Naperville, Illinois, *Annual Operating Budget from May 2014 through April 2015*, Naperville Director of Finance, (Apr. 15, 2014), available at http://www.naperville.il.us/emplibrary/FY15AOBadopted.pdf.

continuing to manually service specific customer premises, customers can opt-out and the city will deactivate the advanced meter's radio transmitter.[35]

- **Indiana.** The Indiana Utility Regulatory Commission declined to approve Duke Energy's proposed seven-year transmission, distribution, and storage system improvements plan. Duke's request included 40 distinct project types or categories, including distribution automation and advanced metering investments. The proposal, denied in part due to insufficient cost estimates, was designed to provide approximately 810,000 Indiana customers with the "first full scale rollout of distribution automation and advanced metering infrastructure technology in the State of Indiana by a large electricity supplier."[36]

- **Maine.** In a December 2014 order, the Maine Public Utilities Commission terminated an investigation into the safety of Central Maine Power Company's (CMP) advanced metering infrastructure, including the use of advanced meters, finding it does not present a credible threat to the health and safety of CMP's customers.[37] An appeal has been filed with the Maine Supreme Judicial Court.[38]

- **Oklahoma.** In April 2015, the Oklahoma Corporation Commission approved with modifications a June 2014 settlement agreement[39] that allows Public Service Company of Oklahoma (PSO) to collect revenues for the installation of advanced meters.[40] PSO announced plans to deploy advanced meters to all electric customers by the end of 2016.[41]

[35] City of Naperville, Illinois, *Question/Response Inventory*, Naperville Smart Grid Initiative, (Mar. 25, 2013) available at http://www.naperville.il.us/emplibrary/Smart_Grid/NSGIQuestionResponseInventory.pdf.

[36] *Verified Petition of Duke Energy Indiana, Inc. for Approval of Petitioner's 7-Year Plan for Eligible Transmission, Distribution and Storage System Improvements[.]*, Docket No. 44526, Order of the Commission (May 8, 2015), *available at* https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b631801c690d.

[37] *Request for Commission Investigation into Smart Meters and Smart Meter Opt-Out,* Docket Nos. 2011-00262 and 2012-00412, December 19, 2014 Order, *available at* https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2011-00262.

[38] *Id.*, Notice of Appeal, January 9, 2015, *available at* https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=84739&CaseNumber=2011-00262.

[39] Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106, Order No. 591186, Cause No. PUD 201300217, Oklahoma Corporation Commission (Apr. 14, 2015), available at http://imaging.occeweb.com/AP/Orders/occ5192886.pdf.

[40] Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185, Issued in Cause No. PUD 201100106, Order No. 639314, Cause No. PUD 201300217, Oklahoma Corporation Commission (June 17, 2014), available at http://imaging.occeweb.com/AP/CaseFiles/occ5114618.pdf.

[41] Public Service Company of Oklahoma, *PSO AMI Project*, *available at* https://www.psoklahoma.com/info/projects/AMIDigitalMeters/.

Chapter 3: Annual resource contribution of demand resources

This chapter summarizes the annual resource contribution from retail and wholesale demand response programs on a national and regional basis from 2012 to 2013, and 2013 to 2014, respectively.[42] Table 3-1 presents data collected by Energy Information Administration (EIA) on 2012 and 2013 potential peak reduction from retail demand response programs within each of the eight regional electricity councils, as well as Alaska and Hawaii. Nationwide, total potential peak reduction[43] from retail demand response programs decreased by 1,408 MW between 2012 and 2013, a drop of 4.9 percent.

Table 3-1: Potential Peak Reduction from Retail Demand Response Programs by NERC Region (2012 & 2013)

NERC Region	Annual Potential Peak Reduction (MW)		Year-on-Year Change	
	2012	2013	MW	%
AK	27	27	0	0.0%
FRCC	3,306	1,924	-1,383	-41.8%
HI	42	35	-7	-16.8%
MRO	5,567	4,264	-1,303	-23.4%
NPCC	606	467	-139	-23.0%
RFC	5,836	5,362	-475	-8.1%
SERC	6,046	8,254	2,209	36.5%
SPP	1,323	1,594	271	20.5%
TRE	480	459	-21	-4.3%
WECC	5,269	4,681	-588	-11.2%
Unspecified	0	28	28	--
Total	**28,503**	**27,095**	**-1,408**	**-4.9%**

Sources: EIA, EIA-861 Demand_Response_2013 and Utility_Data_2013 data files.

Note: Figures from source data are rounded to the nearest megawatt for publication. The percentage change is calculated based on the unrounded figures. Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

Regionally, however, there were large differences in the change in potential peak reduction from 2012 to 2013. For example, Table 3-1 above indicates potential peak reduction increased in the SERC Reliability Corporation (SERC) region by approximately 2,200 MW compared to the previous year, due to a large increase in reported savings from industrial programs operated by the Tennessee Valley Authority (TVA). In other regions, potential peak reductions decreased on

[42] The latest publicly available retail and wholesale data sets are used to determine the annual resource contributions from retail and wholesale demand response programs; these include EIA retail data for 2012 and 2013, as well as ISO/RTO wholesale data for 2014.

[43] Potential peak reduction (or potential peak demand savings) refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called." U.S. EIA, Form EIA-861 Instructions, Schedule 6, Part B.

a large absolute and percentage basis. The Florida Reliability Coordinating Council (FRCC) saw a reduction of 1,383 MW of potential peak savings, nearly a 42 percent drop, due to much lower reported savings from Florida Power & Light's demand response programs. Similarly, in the Midwest Reliability Organization (MRO) region there was a 1,300 MW drop in potential peak savings, a 23 percent decrease, due to lower reported savings from programs operated by Nebraska Public Power District and Northern States Power Company – Minnesota.

As shown in Table 3-2 below, in 2013, industrial customer demand response represented 55 percent of potential peak reduction in retail programs, an increase of eight percentage points over 2012. Residential and commercial customer demand response accounted for 26 and 19 percent of potential peak reduction from retail programs in 2013, respectively, a slight drop from the previous year. The relative contribution by customer class varies by region. For example, residential demand response programs account for the largest portion of potential peak reduction in FRCC (approximately 42 percent) and MRO (approximately 44 percent), and Hawaii (approximately 57 percent). In contrast, commercial programs accounted for the majority of potential peak reduction in Alaska, Northeast Power Coordinating Council (NPCC) and Texas Reliability Entity (TRE); and industrial programs accounted for the majority in ReliabilityFirst Corporation (RFC), SERC, Southwest Power Pool RE (SPP), and Western Electricity Coordinating Council (WECC). As the figures show, the majority of potential peak reduction continues to come from industrial programs.

Table 3-2: Potential Peak Reduction (MW) from Retail Demand Response Programs by Region and Customer Class (2013)

NERC Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	817	750	357	0	1,924
HI	20	15	0	0	35
MRO	1,865	801	1,598	0	4,264
NPCC	38	256	160	13	467
RFC	1,545	684	3,133	0	5,362
SERC	1,348	810	6,095	1	8,254
SPP	213	324	1,057	0	1,594
TRE	88	341	31	0	459
WECC	1,037	1,130	2,361	154	4,681
Unspecified	28	0	0	0	28
All Regions	**7,003**	**5,124**	**14,800**	**168**	**27,095**

Source: EIA, EIA-861 Demand_Response_2013 and Utility_Data_2013 data files.

Note: Figures from source data are rounded to the nearest megawatt for publication. Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

Table 3-3 below presents potential peak reduction from wholesale demand response programs in 2013 and 2014. Overall, potential peak reduction rose slightly in 2014 to 28,934 MW, a 0.5 percent increase from the previous year, and accounted for 6.2 percent of peak demand in 2014, essentially unchanged from 2013. Since 2009, potential peak reduction from demand response in wholesale markets has increased by approximately 6 percent, but peak demand has also increased by a similar amount, resulting in little net change in the contribution of demand response to meeting peak demand.[44]

Table 3-3: Potential Peak Reduction from U.S. ISO and RTO Demand Response Programs

RTO/ISO	2013 Potential Peak Reduction (MW)	2013 Percent of Peak Demand [8]	2014 Potential Peak Reduction (MW)	2014 Percent of Peak Demand [8]
California ISO (CAISO)	2,180 [1]	4.8%	2,316 [9]	5.1%
Electric Reliability Council of Texas (ERCOT)	1,950 [2]	2.9%	2,100 [10]	3.2%
ISO New England, Inc. (ISO-NE)	2,100 [3]	7.7%	2,487 [11]	10.2%
Midcontinent Independent System Operator (MISO)	9,797 [4]	10.2%	10,356 [12]	9.0%
New York Independent System Operator (NYISO)	1,307 [5]	3.8%	1,211 [13]	4.1%
PJM Interconnection, LLC (PJM)	9,901 [6]	6.3%	10,416 [14]	7.4%
Southwest Power Pool, Inc. (SPP)	1,563 [7]	3.5%	48 [15]	0.1%
Total ISO/RTO	**28,798**	**6.1%**	**28,934**	**6.2%**

Sources:
[1] CAISO 2013 Annual Report on Market Issues & Performance
[2] ERCOT Quick Facts (Nov. 2013)
[3] ISO-NE Demand Response Asset Enrollments (Jan. 8, 2014), p. 2.
[4] 2013 State of the Market Report for the MISO Electricity Markets, p.72. This figure excludes 366 MW of emergency demand response that is also classified as LMR
[5] 2013 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc., ER01-3001, et al. (Jan. 15, 2014)
[6] PJM 2013 Demand Response Operations Markets Activity Report, pp. 3-4 (Apr. 18, 2014). Figure represents “unique MW.”
[7] SPP Fast Facts (as of Dec. 2013)
[8] Sources for peak demand data include: California ISO 2013 & 2014 Annual Reports on Market Issues and Performance; ERCOT 2013 & 2014 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report (Apr. 2014 & Apr. 2015); 2013 & 2014 State of the Market Reports for the MISO Electricity Markets; 2013 & 2014 State of the Market Reports for the New York ISO Markets; 2013 & 2014 PJM State of the Markets Reports, Vol. 2; SPP 2013 State of the Market Report; SPP Fast Facts (Dec., 2014).
[9] CAISO 2014 Annual Report on Market Issues & Performance, Table 1.3, p. 32 (June 2015)
[10] ERCOT Quick Facts (Dec. 2014)
[11] ISO-NE Demand Response Asset Enrollment, presented at Demand Resources Working Group Meeting (Jan. 7, 2015) (data as of Jan. 1, 2015), p. 2.
[12] 2014 State of the Market Report for the MISO Electricity Market (June 2015)
[13] 2014 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., ER01-3001 (Jan. 15, 2015), Table 1, p. 7
[14] PJM 2014 Demand Response Operations Markets Activity Report (Apr. 2015), p. 5. Figure represents “unique MW.”
[15] SPP Fast Facts (as of Dec. 31, 2014).

Note: Commission staff has not independently verified the accuracy of the RTO, ISO and Independent Market Monitor reports. Values from source data are rounded for publication.

Regionally, demand response participation increased in five of the seven ISOs/RTOs in 2014: CAISO, ERCOT, ISO-NE, MISO, and PJM. Of these, the largest absolute increases in

[44] Data for 2009 obtained from the 2011 Assessment of Demand Response and Advanced Metering Staff Report (Nov. 2011), *available at* http://www.ferc.gov/legal/staff-reports/11-07-11-demand-response.pdf.

megawatts occurred in MISO with approximately 560 MW, and PJM for which demand response potential rose by more than 500 MW. On a percentage basis, the largest increase in potential peak reduction in 2014 occurred in ISO-NE, where enrollments rose by 18 percent—approximately 390 MW—to 2,487 MW, after declining by nearly 25 percent from 2012 to 2013. The majority of the 2014 ISO-NE increase is due to a large growth in enrollment of on-peak demand resources;[45] only one of the eight ISO-NE load zones saw a slight decrease in on-peak demand resources in 2014.[46] This increase in on-peak demand resource enrollment may, in turn, be the result of greater spending on demand-side management programs by utilities in the New England states. According to data from the Consortium for Energy Efficiency, budgets for these programs in the six New England states comprising the ISO-NE region increased by approximately 20 percent from 2013 to 2014.[47]

In contrast, wholesale demand response potential appeared to fall dramatically in SPP, by more than 1,500 MW. According to the SPP Market Monitoring Unit, this was due to reclassification of certain behind-the-meter resources, cogeneration facilities, and industrial loads as special case generation resources after the introduction of the Integrated Marketplace in March 2014.[48] Under the previous Energy Imbalance Services market, there was no special resource registration category for demand response resources. With this change, wholesale demand response as defined and reported by SPP fell to less than one percent of peak demand in 2014.

[45] *See* Commission Letter Order, 150 FERC ¶ 61,120, Feb. 20, 2015, at 2, "An On-Peak Demand Resource is a type of non-dispatchable ('passive') demand resource that neither receives nor responds to Dispatch Instructions (as opposed to dispatchable, 'active' demand resources, which are required to respond to Dispatch Instructions). On-Peak Demand Resources are often comprised of Distributed Generation, Energy Efficiency, or Load Management assets."

[46] Figures are derived from data published by ISO-NE. *See*: "ISO-NE Demand Response Asset Enrollments," presented at Demand Resources Working Group Meeting, January 7, 2015, *available at* http://www.iso-ne.com/static-assets/documents/2014/12/a01_intro_drwg_mtg_1_07_2015.ppt; and "ISO-NE Demand Response Asset Enrollments," presented at Demand Resources Working Group Meeting, January 8, 2014, *available at* http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2014/jan82014/a01_intro_drwg_mtg_01_08_2014_r1.ppt.

[47] Figures are derived from data published by the Consortium for Energy Efficiency. *See* the 2013 and 2014 *Annual Industry Report*, *Efficiency Program Industry by State and Region Appendices,* Table 4, April 2014 and April 2015, *available at* http://www.cee1.org/annual-industry-reports.

[48] Catherine Tyler Mooney, SPP Market Monitoring Unit Manager, e-mail correspondence, (May 7, 2015).

NYISO also reported a continued drop in the number of resources participating in its reliability demand response program, which accounts for 93 percent of demand response resource participation in the region.[49] According to the May 2015 market monitor report, several factors led to this continuing decline: 1) changes to the calculation of baselines for resources participating in the program, 2) an increase in the number of audits to improve baseline accuracy, and 3) reduced revenues from low capacity prices for some areas in recent years.[50] NYISO's improvements in baseline calculation reduced the amount of capacity some demand response resources were qualified to sell, and its increased auditing allowed NYISO to identify resources that might have had unreported change in status that reduce their ability to deploy.[51] Despite this drop in program participation in 2014 due to mild summer weather, demand response enrollments increased slightly as a percentage of peak demand.

[49] NYISO, 2014 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc., ER01-3001 (Jan. 15, 2015), pp. 4-5.

[50] Potomac Economics, *2014 State of the Market Report for the New York ISO Markets* (May 2015), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2014/NYISO2014SOMReport__5-13-2015_Final.pdf.

[51] *Id.* at p. 96.

Chapter 4: Potential for demand response as a quantifiable, reliable resource for regional planning purposes

The American Recovery and Reinvestment Act of 2009 (Recovery Act) recognized the need to develop a body of interconnection-level transmission analysis designed to identify new or greatly upgraded lines that could be required under a wide range of potential futures,[52] and included scenarios of reduced load growth due to demand response resources. In January 2015, Oak Ridge National Laboratory released a review of the results from these broad-based transmission studies, which were developed collaboratively among industry experts and representatives from states, federal agencies, and key non-governmental organizations,[53] and provided for each of the three physical interconnections in the United States: the Western Interconnection, the Eastern Interconnection, and the Electric Reliability Council of Texas.[54]

In January 2014, President Obama issued a Presidential Memorandum establishing an interagency task force charged with developing a Quadrennial Energy Review (QER).[55] With an initial focus on transmission, distribution and storage infrastructure, a key finding of the QER is the expectation that "large transmission and distribution investments will be made to replace aging infrastructure; maintain reliability; enable market efficiencies; and aid in meeting policy objectives, such as [greenhouse gas] reduction and state renewable energy goals."[56] The QER notes "[F]lexible grid system operations and demand response can enable renewables and reduce the need for new bulk-power-level infrastructure. End-use efficiency, demand response, storage, and distributed generation can reduce the expected costs of new transmission investment."[57] Five key policy principles are contained within the QER's "Policy Framework for the Grid of the Future," one of which advises that "[t]he future grid should encourage and enable energy efficiency and demand response to cost effectively displace new and existing electric supply infrastructure, whether centralized or distributed."[58]

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[52] U.S. Department of Energy (DOE), DOE Support for Interconnection-Level Analysis and Planning, NARUC Summer Meetings presentation, July 2009, p. 3, *available at* http://www.narucmeetings.org/Presentations/DHM%20to%20NARUC%2007%2013%2009.pdf.

[53] Hadley, S.W. and A.H. Sanstad. "Impacts of Demand-Side Resources on Electric Transmission Planning Demand Resources and Transmission Requirements." Oak Ridge National Laboratory and Lawrence Berkeley National Laboratory (ORNL/TM-2014/568, LBNL–XXX), January 2015, *available at* http://energy.gov/sites/prod/files/2015/01/f19/Impact_DSR_on_Transmission_PlanningV6_0.pdf.

[54] DOE, Recovery Act Interconnection Transmission Planning, *available at* http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act.

[55] The White House, Presidential Memorandum -- Establishing a Quadrennial Energy Review, January 9, 2014, a*vailable at* https://www.whitehouse.gov/the-press-office/2014/01/09/presidential-memorandum-establishing-quadrennial-energy-review.

[56] DOE, Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure, April 2015, p. S-14, *available at* http://energy.gov/sites/prod/files/2015/05/f22/QER%20Full%20Report_0.pdf.

[57] *Id.* at S-15.

[58] *Id.* at 3-24.

Chapter 5: Existing demand response programs and time-based rate programs and steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party

The chapter provides information on demand response programs and time-based rate programs in 2012 and 2013, and summarizes recent federal, regional, state, and industry demand response actions. Tables 5-1 and 5-2 present customer enrollments in incentive-based[59] and time-based[60] demand response programs for 2012 and 2013, respectively. As shown in Table 5-1, from 2012 to 2013, the number of customers enrolled in incentive-based programs nationwide increased by almost 70 percent to more than nine million customers. Several of the utilities experiencing large growth in program enrollments from 2012 to 2013 received grants under the American Recovery and Reinvestment Act of 2009's Smart Grid Investment Grants (SGIG) for the deployment of advanced meters and associated infrastructure,[61] and these SGIG investments may be a contributing factor in the increased deployment of new demand response programs.

On a regional basis, customer enrollment increased by nearly 240 percent in Western Electricity Coordinating Council (WECC) from 2012 to 2013, to more than three million customers. Energy Information Administration (EIA) data indicates this is due to large increases in reported enrollments for the Southern California Edison, San Diego Gas & Electric and Arizona Public Service residential programs, as well, the Pacific Gas & Electric residential and commercial programs, and Public Service Company of New Mexico industrial programs. Additionally, enrollment in incentive-based programs more than doubled in Southwest Power Pool RE (SPP), due to increased enrollment in programs run by Oklahoma Gas & Electric (OG&E), Westar Energy, Kansas Gas & Electric, and Southwestern Public Service Company. Moreover, notable increases in program enrollments were also realized in the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), ReliabilityFirst Corporation (RFC), and SERC Reliability Corporation (SERC) regions.

[59] Incentive-based demand response programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part C.

[60] Time-based rate programs include real-time pricing, critical peak pricing, variable peak pricing, and time-of-use rates administered through a tariff. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part C.

[61] U.S. Department of Energy (DOE), "Recovery Act Selections For Smart Grid Investment Grant Awards – By State," updated November 2011, *available at* http://www.energy.gov/oe/downloads/recovery-act-selections-smart-grid-investment-grant-awards-state-updated-november-2011.

Table 5-1: Customer Enrollment in Incentive-based Demand Response Programs, by NERC Region (2012 & 2013)

NERC Region	Enrollment in Incentive-based Programs		Year-on-Year Change	
	2012	2013	Customers	%
AK	2,432	2,468	36	1%
FRCC	1,328,487	1,554,830	226,343	17%
HI	36,703	36,332	-371	-1%
MRO	795,345	1,248,723	453,378	57%
NPCC	54,413	62,631	8,218	15%
RFC	1,398,341	1,852,985	454,644	33%
SERC	715,225	1,084,449	369,224	52%
SPP	91,585	193,507	101,922	111%
TRE	109,875	138,613	28,738	26%
WECC	884,299	3,002,607	2,118,308	240%
Unspecified	15,004	10,205	-4,799	-32%
Total	**5,431,709**	**9,187,350**	**3,755,641**	**69%**

Sources: EIA, EIA-861 dsm_2012, utility_data_2012, and Demand_Response_2013 data files.

Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

As Table 5-2 indicates, below, nationwide enrollment in time-based programs increased significantly from 2012 to 2013 by 60 percent. The bulk of the increase in customer enrollments occurred in the SPP region with over one million new customer enrollments, and the RFC region with over 1.5 million new customer enrollments. EIA data indicates the increase in time-based program enrollments for the SPP region is largely due to Public Service Company of Oklahoma,[62] Southwestern Electric Power Company, and OG&E programs provided for all customer classes.[63] RFC also experienced large increases in enrollment, primarily due to significant enrollment increases in residential programs run by Ohio Power, PEPCO, BG&E, Delmarva Power and Wisconsin Electric. In FRCC, enrollment fell by approximately ten thousand customers due to lower reported Florida Power & Light and Tampa Electric Company program enrollments. Data within the table's "Unspecified" region also shows growth in time-based customer participation, reflecting an increase in residential time-based program

[62] Public Service Company of Oklahoma indicates that it redesigned its demand side management program portfolio for the 2013-2015 program years. *See Public Service Company of Oklahoma 2013 Energy Efficiency and Demand Response Programs: Annual Report*, June 1, 2014, *available at* http://www.occeweb.com/pu/DSM%20Reports/2013_PSO_Demand_Programs_Annual_Report.pdf.

[63] In 2013, OG&E added two new programs to its demand side management program portfolio. One of these was the SmartHours program, a program for residential and small commercial customers combining dynamic pricing and enabling technology. *See*: Oklahoma Gas and Electric, *2013 Oklahoma Demand Programs Annual Report*, June 2014, *available at* http://www.occeweb.com/pu/DSM%20Reports/2013_OGE_Demand%20_Programs_Annual_Report.pdf.

enrollments for TXU Energy Retail, and newly reported programs from several other retail power marketers.[64]

Table 5-2: Customer Enrollment in Time-based Demand Response Programs, by NERC Region (2012 & 2013)

NERC Region	Enrollment in Time-based Programs		Year-on-Year Change	
	2012	2013	Customers	%
AK	38	43	5	13%
FRCC	27,089	16,203	-10,886	-40%
HI	323	365	42	13%
MRO	82,310	108,527	26,217	32%
NPCC	293,721	258,426	-35,295	-12%
RFC	433,879	1,977,536	1,543,657	356%
SERC	180,619	236,662	56,043	31%
SPP	61,618	1,143,774	1,082,156	1,756%
TRE	604	968	364	60%
WECC	2,601,112	2,146,548	-454,564	-17%
Unspecified	57,435	88,229	30,794	54%
Total	**3,738,748**	**5,977,281**	**2,238,533**	**60%**

Sources: EIA, EIA-861 dsm_2012,utility_data_2012, and Dynamic_Pricing_2013 data files.
Note: Although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. Commission staff has not independently verified the accuracy of EIA data.

FERC demand response orders and activities

On May 23, 2014, in a split ruling in the case of *Electric Power Supply Association v. FERC*, No. 11-1486 (D.C. Cir. May 23, 2014) (*EPSA*), the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) vacated and remanded FERC's final rule on demand response compensation in organized wholesale electric markets (*Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322, order on reh'g, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *order on reh'g*, Order No. 745-B, 138 FERC ¶ 61,148 (2012)). The court held that the Commission lacks authority under the Federal Power Act to regulate the compensation that wholesale energy markets pay for demand response as a supply resource. On January 15, 2015, the U.S. Solicitor General and EnerNOC filed petitions for writ of certiorari in the U.S. Supreme Court. On May 5, 2015, the U.S. Supreme Court agreed to hear the case.[65] Oral arguments before the U.S. Supreme Court occurred on October 14, 2015, and a final decision will likely be issued by June, 2016.

[64] Power marketers are not required to specify a NERC region when responding to the EIA-861 survey. *See* EIA, Form EIA-861, Schedule 2, Part A, *available at* http://www.eia.gov/electricity/data/eia861/.

[65] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *cert. granted*, 83 U.S.L.W. 3643 (U.S. May 4, 2015) (Nos. 14-840, 14-841).

The Commission issued several orders related to demand response during the last year. In an order issued January 9, 2015,[66] the Commission approved a proposal by ISO-NE to fully integrate demand response resources into its wholesale energy markets, including its reserve markets. While the Commission acknowledged that the *EPSA* decision creates uncertainty for demand response resources in FERC-jurisdictional wholesale markets, the Commission stated that "we find it appropriate at this time to proceed with these market enhancements until further action is taken."

On March 31, 2015,[67] the Commission rejected a proposal from PJM to alter the way demand response resources participate in the capacity market effective April 1, 2015. PJM requested that the proposed revisions be in effect for the 2015 Base Residual Auction, in the event that the Supreme Court denied certiorari requests for *EPSA*. The Commission found that PJM's filing was premature.

On July 22, 2015,[68] the Commission granted complaints concerning the inability of demand response to participate in the transition auctions associated with PJM's Capacity Performance initiative. With regards to the uncertainty associated with the Supreme Court's review of the *EPSA* decision, the Commission stated that "we disagree that any uncertainty at this point provides a basis for finding that non-generation resources are not similarly-situated to Generation Capacity Resources."

Other federal demand response activities

Executive Order 13693: Planning for Federal Sustainability in the Next Decade

On March 19, 2015 President Obama signed Executive Order 13693: *Planning for Federal Sustainability in the Next Decade*.[69] This Executive Order directs federal agencies to increase efficiency and improve environmental performance. Among other actions, it 1) directs federal agencies to reduce greenhouse gas emissions 40 percent over the next decade (from 2008 levels), 2) promotes building energy conservation, efficiency, and management by directing the reduction of agency building energy intensities and various measures including participation in life-cycle cost-effective demand management programs beginning in fiscal year 2016, and 3) directs an increase in the percentage share of renewable electric energy for total building electric consumption to no less than 30 percent by fiscal year 2025. The Executive Order also provides guidance pertaining to fleet management, sustainable acquisitions, pollution prevention, and water and energy usage.

Smart Grid Investment Grant consumer behavior studies

As part of SGIG, the U.S. Department of Energy (DOE) sponsored consumer behavior studies at ten utilities in the United States. These customer behavior studies applied randomized and controlled experimental designs for estimating customer responses to time-based retail rates to provide new information for improving program designs, implementation strategies, and

[66] ISO New England Inc, 150 FERC ¶ 61,007 (2015).

[67] PJM Interconnection, L.L.C., 150 FERC ¶ 61,251 (2015).

[68] PJM Interconnection, L.L.C., 152 FERC ¶ 61,064 (2015).

[69] Executive Order 13693 3 C.F.R, pp 15871-15884 (2015) *available at* http://www.gpo.gov/fdsys/pkg/FR-2015-03-25/pdf/2015-07016.pdf.

evaluations. The DOE released an interim report on the results of these studies in June 2015.[70] The interim report presents interim results for six utilities and both the interim and final evaluations for four utilities that were completed by December 31, 2014. Key findings from these utility studies include: 1) enrollment rates were much higher and peak demand reductions were generally lower under opt-out recruitment approaches than opt-in approaches, and opt-out approaches were more cost-effective; 2) customer retention rates were higher for critical peak rebate programs than for critical peak pricing programs; 3) demand reductions achieved without enabling control technology were generally higher for critical peak pricing than for critical peak rebates,[71] with the caveat that when smart thermostats were available as an automated control strategy, the differences in peak demand reductions between critical peak pricing and critical peak rebates were largely eliminated; and 4) free in-home display and smart thermostat offers did not substantially affect enrollment and retention rates, but peak demand reductions were substantially higher when smart thermostats were used, leading to favorable benefit-cost ratios for smart thermostat programs.

U.S. Department of Defense

The U.S. Department of Defense (DOD) is the single largest energy consuming entity in the United States.[72] Managing over 500 installations worldwide, DOD facilities comprise a diverse mix of nearly 300,000 buildings of various vintages and include barracks, commissaries, data centers, office buildings, laboratories, and maintenance depots.[73] In addition to investing in conservation and efficiency projects,[74] U.S. Government Accountability Office (GAO) data indicates that at least 56 of 450 domestic DOD installations have participated in demand response programs since 2009.[75] GAO states the DOD has both department-wide energy management initiatives and service-level initiatives underway that could facilitate DOD installation participation in demand response programs. These include the expanded use of advanced meters, smart grid initiatives, and DOD's plug-in electric vehicle pilot program.[76]

Separately, the DOD environmental research programs continue to foster collaborative federal, academic, and industry opportunities to conduct research and development, to identify and demonstrate cost-effective technologies, and to promote the transfer of innovative technologies

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[70] DOE, Office of Electricity Delivery and Energy Reliability, Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, SmartGrid.Gov, June 2015, *available at* www.smartgrid.gov/files/CBS_interim_program_impact_report_FINAL.pdf.

[71] Critical peak pricing is a rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours. Critical peak rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like critical peak pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.

[72] U.S. Department of Defense (DOD), Office of the Deputy Under Secretary of Defense (Installations and Environment), Department of Defense Annual Energy Management Report: Fiscal Year 2013, June 2014, p. 15, *available at* http://www.acq.osd.mil/ie/energy/energymgmt_report/FY%202013%20AEMR.pdf.

[73] *Id.* at 5.

[74] *Id.*

[75] U.S. Government Accountability Office, Electricity Markets: Actions Needed to Expand GSA and DOD Participation in Demand-Response Activities, GAO-14-594, July 2014, *available at* http://gao.gov/products/GAO-14-594.

[76] *Id.* at 15-16.

into the markets.[77] A featured initiative of the DOD's environmental research programs is the DOD's "Installation Energy Test Bed" to demonstrate new energy technologies in a real-world, integrated building environment so as to reduce risk, overcome barriers to deployment, and facilitate wide-scale commercialization.[78] DOD's environmental research programs support initiatives that directly and indirectly support demand response programs.[79]

U.S. General Services Administration

The U.S. General Services Administration (GSA) owns and leases over 370 million square feet in 9,624 buildings,[80] and has general statutory authority to enter into utility service contracts and provide energy management and audit services for federal agencies. GSA's Energy Division disseminates policies and guidance documents related to energy management issues, including demand response participation.[81] Since 2012, the GSA Energy Division has helped GSA regions identify and enroll in potential demand response programs by organizing and holding competitive auctions that solicit demand response aggregators' assessments of available opportunities along with estimated financial benefits.[82] Six of the eleven GSA regions that span the country have participated in demand response programs.[83] In April 2015, GSA reported that its demand response efforts had enrolled 17 federal buildings in NYISO and PJM demand response programs resulting in $1.1 million in rebates to the agencies since 2011.[84]

The GSA has also released an innovative green building learning simulation called "Green the Building" as a part of its Sustainable Facilities Tool (SFTool).[85] The simulation, which includes demand response, places users in the role of a resource-constrained decision-maker, charged with greening buildings through strategic energy, waste, water, and occupant satisfaction improvements.[86]

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[77] DOD, DOD's Environmental Research Programs: About SERDP and ESTCP, *available at* https://www.serdp-estcp.org/About-SERDP-and-ESTCP.

[78] DOD, DOD's Environmental Research Programs, Installation Energy Test Bed, *available at* https://www.serdp-estcp.org/Featured-Initiatives/Installation-Energy.

[79] Fiscal Year 2015 new start project selections include *Utilization of Advanced Conservation Voltage Reduction (CVR) for Energy Reduction on DoD Installations (W-2015).* The Strategic Environmental Research and Development Program (SERDP) and the Environmental Security Technology Certification Program (ESTCP) maintain a database of active and completed projects that is available at https://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/(list)/1/.

[80] U.S. General Services Administration (GSA), Public Building Service, *available at* http://www.gsa.gov/portal/category/21391.

[81] U. S. Government Accountability Office, Electricity Markets: Actions Needed to Expand GSA and DOD Participation in Demand-Response Activities, GAO-14-594 (July 2014), p. 6, *available at* http://gao.gov/assets/670/664753.pdf.

[82] *Id.* at 12.

[83] *Id.* at 19.

[84] GSA, "GSA Reaches Million Dollar Mark in Demand Response Rebates," The GSA Blog, April 29, 2015, *available at* http://gsablogs.gsa.gov/gsablog/2015/04/29/gsa-reaches-million-dollar-mark-in-demand-response-rebates/.

[85] GSA, Greening the Building, *available at* https://sftool.gov/practice#about.

[86] FedCenter.gov, GSA Releases "Greening The Building" Tool, *available at* https://www.fedcenter.gov/Announcements/index.cfm?id=27440&pge_prg_id=27142&pge_id=1860.

U.S. Department of Veteran's Affairs

The U.S. Department of Veteran's Affairs oversees 1,886 facilities,[87] including the Nation's "largest integrated health care system consisting of 152 medical centers, in addition to nearly 1400 community-based outpatient clinics, community living centers, Vet Centers and Domiciliaries."[88] In addition to participating in NYISO demand response programs,[89] in 2014 the U.S. Department of Veteran's Affairs released a sustainable design manual to consolidate sustainable design requirements into a single resource. The manual discusses demand response programs as a site option; as well, the steps to determine what, if any, demand response programs are available and applicable for facilities based in a life-cycle cost assessment.[90]

U.S. Postal Service

The U.S. Postal Service operates more than 32,000 buildings nationwide with facilities dedicated to mail processing, retail services, vehicle maintenance, data management centers and administrative offices.[91] The U.S. Postal Service states that approximately 50 U.S. Postal Service facilities are currently participating in grid and utility sponsored demand response programs in the Northeast, Capital and Western Areas, and, in fiscal year 2014, the program was expanded into municipal and cooperative utility areas.[92]

State legislative and regulatory activities related to demand response

This section highlights developments in retail demand response and time-based pricing activities since staff's 2014 report.

- **California.** In July 2015, the California Public Utilities Commission (CPUC) unanimously approved[93] a proposal to, among other things, reduce the number of residential rate tiers from four to two, establish default time-of-use (TOU) rates for residential customers starting in 2019 (with an option to remain on the simplified tiered rates), add a "Super-User" surcharge for very large electricity users, and require the state's three investor-owned utilities (IOUs) to create an outreach program to educate customers in the lower usage tiers about no-cost and low cost energy efficiency measures. As part of the transition to default TOU rates, California's IOUs must immediately begin designing pilots to test both default and opt-in TOU rate structures for their residential customers. The utilities must file their proposals for rate changes on January 1, 2018. In

[87] U.S. Department of Veteran's Affairs, Locations, *available at* http://www.va.gov/directory/guide/home.asp?isflash=1.

[88] U.S. Department of Veteran's Affairs, Where do I get the care I need?, *available at* http://www.va.gov/health/findcare.asp.

[89] DOE, 2013 Federal Energy and Water Management Award Winners, *available at* http://energy.gov/eere/femp/2013-federal-energy-and-water-management-award-winners.

[90] U.S. Department of Veteran's Affairs, Office of Construction & Facilities Management, Sustainable design manual, May 2014, p. 23, *available at* http://www.cfm.va.gov/til/sustain/dmSustain.pdf.

[91] U.S. Postal Service, U.S. Postal Service 2014 Strategic Sustainability Performance Plan (June 30, 2014), p. 3, *available at* http://about.usps.com/what-we-are-doing/green/pdf/2014_USPS_SSPP.pdf.

[92] U.S. Postal Service, National Energy Management Strategy, December 2013, p. 25, *available at* https://about.usps.com/what-we-are-doing/green/pdf/nemp-31dec13.pdf.

[93] CPUC, "CPUC Creates New Electricity Rate Design Structure That Reflects Actual Costs and Supports Renewables," press release, July 3, 2015, *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K072/153072586.PDF.

addition, the CPUC decision rejects a proposal made by the utilities for a fixed monthly charge that would have applied to all residential customers, but leaves open the possibility that such a charge could be considered in some form after TOU rates have been implemented. Instead of requiring customers to pay a fixed monthly amount, the IOUs must propose and implement an amount that is equal to or less than the fixed monthly charge (i.e., a "minimum bill") this year.[94]

California also took action to develop the ability of its electric utilities to engage in distribution resource planning. A new Section 769 of the state's Public Utilities Code requires that "electrical corporations" file distribution resource plan proposals by July 1, 2015.[95] These plan proposals are required to "identify optimal locations for the deployment of distributed resources." Pursuant to Section 769, the Commission instituted a rulemaking on August 13, 2014 (R. 14-08-013). Following the issuance of an Assigned Commissioner's Ruling on Guidance for Public Utilities in February on these required distribution resource plans, the major California electric utilities filed their plans on July 1, 2015.[96]

- **Hawaii.** As noted in the 2014 staff report, the Hawaii Public Utilities Commission (HI PUC) ordered the Hawaiian Electric Company (HECO) and its subsidiaries to establish comprehensive goals and metrics for their demand response programs, and to consolidate existing and planned programs into an integrated portfolio.[97] As of the most recent order in the same docket, the HI PUC was still reviewing the Integrated Demand Resource Portfolio Plan (IDRPP) submitted by HECO in July 2014, and subsequent comments, to assess whether the plan complies with previous directives. Because it has yet to issue an order on the IDRPP, the HI PUC found that the existing demand response programs may continue without modification for the 2015 program year.[98]

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[94] Decision On Residential Rate Reform For Pacific Gas And Electric Company, Southern California Edison Company, And San Diego Gas & Electric Company And Transition To Time-Of-Use Rates [Proposed], Rulemaking 12-06-013, (CPUC Apr 21, 2015), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K024/153024891.PDF.

[95] AB 327, An act to amend Sections 382, 399.15, 739.1, 2827, and 2827.10 of, to amend and renumber Section 2827.1 of, to add Sections 769 and 2827.1 to, and to repeal and add Sections 739.9 and 745 of, the Public Utilities Code, relating to energy (Approved October 7, 2013), Sec. 8, available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[96] Pacific Gas & Electric's filing is *available at* http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=340658, San Diego Gas & Electric's filing is available at https://www.sdge.com/sites/default/files/regulatory/A_15-07-SDG&E_DRP_Application.pdf , and Southern California Edison's filing is *available at* http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/BF42F886AA3F6EF088257E750069F7B7/$FILE/A.15-07-XXX_DRP%20Application-%20SCE%20Application%20and%20Distribution%20Resources%20Plan%20.pdf.

[97] Federal Energy Regulatory Commission, *2014 Assessment of Demand Response and Advanced Metering: Staff* Report, December 2014, p. 23.

[98] Confirming That Hawaiian Electric Company And Maui Electric Company May Continue Existing Demand Response Programs Without Modification And Approving The Use Of The Demand Side Management Mechanism To Recover Incentive Payments Made In Conjunction With Existing Demand Response Programs, Order No. 32660, Docket No. 2007-0341, (HI PUC Feb 2, 2015), *available at* http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A15B03B10255G2729218+A15B03B35856A151661+14+1960.

- **Idaho.** In March 2015, Idaho Power filed its 2014 Demand-side Management Annual Report and requested a finding from the Idaho Public Utilities Commission (IPUC) that Idaho Power's expenditures in 2014 for energy efficiency and demand response programs were prudently incurred.[99] The 2014 Annual Report states that Idaho Power achieved 378 MW of non-coincident load reduction from its three demand response programs in 2014, out of total program enrollment of 390 MW.[100] The IPUC temporarily suspended two of Idaho Power's three demand response programs in 2013 and opened a proceeding to assess the continued need for the programs. This proceeding resulted in settlement proceedings stipulating that the programs would be restarted in 2014.[101] In May 2015, the IPUC approved Idaho Power's application to replace its demand response program aimed at commercial and industrial customers – formerly called the "FlexPeak Management Program" – with a new "Flex Peak Program." The IPUC also approved Idaho Power's request that the utility operate the new program in place of a third-party demand response aggregator, which had operated the previous commercial and industrial program since its creation in 2009. However, the IPUC stipulated that Idaho Power must file a report within a year examining its own experience with internally managing the program.[102]

- **Illinois.** Commonwealth Edison (ComEd) has partnered with Comcast and Nest to offer its customers a choice of smart thermostat demand response programs: Xfinity Home's "Summer Energy Management Program" or Nest's "Rush Hour Rewards." The program allows ComEd to remotely adjust thermostat settings on peak days, but gives customers the ability to override the temperature setting at any time. The first 10,000 customers that enroll by the end of May from either program receive an incentive of $40 on top of any energy savings.[103]

- **Michigan.** The Michigan Public Service Commission (MPSC) in June 2015 directed DTE Electric and Consumers Energy to implement time-based rate tariffs for their customers. The MPSC directed DTE Electric to, by January 1, 2016, make TOU rates and dynamic peak pricing available on an opt-in basis to all customers with an AMI

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[99] In The Matter Of The Application Of Idaho Power Company For A Determination Of 2014 Demand-side Management ("DSM") Expenses As Prudently Incurred, Case No. IPC-E-15-16, (IPUC Mar 13, 2015), *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1506/20150313application.pdf.

[100] Idaho Power, Demand-Side Management: 2014 Annual Report, March 15, 2015, p. 20, *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1506/201503162014%20DSM%20ANNUAL%20REPORT.PDF.

[101] In the Matter of Idaho Power Company's A/C Cool Credit, Irrigation Peak Rewards and FlexPeak Demand Response Programs for 2014 and Beyond, Order No. 32923, Case No. IPC-E-13-14, (IPUC Nov 12, 2013) *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1314/ordnotc/20131112FINAL_ORDER_NO_32923.PDF.

[102] In the Matter of Idaho Power Company's Application for Approval of New Tariff Schedule 82, A Commercial and Industrial Demand-Response Program (Flex Peak Program), Order No. 33292, Case No. IPC-E-15-03, (May 7, 2015), *available at* http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1503/ordnotc/20150507FINAL_ORDER_NO_33292.PDF.

[103] Greentech Media, "Comcast makes another move into home energy services," *available at* http://www.greentechmedia.com/articles/read/Comcast-Joins-ComEds-Residential-Demand-Response-Program.

metered installed for at least one year.[104] Similarly, Consumers Energy must make TOU and dynamic peak pricing rates available on an opt-in basis to its customers by January 1, 2017, subject to further action from the MPSC on the company's advance meter roll-out in the pending rate case.[105] In addition, both utilities must file a plan within 90 days outlining plans for education, outreach, marketing and customer support related to TOU rates dynamic peak pricing.

- **Minnesota.** In December 2014, the e21 Initiative, a collaborative composed of The Great Plains Institute, Center for Energy and Environment, Energy Systems Consulting Services, George Washington University Law School, Xcel Energy, and Minnesota Power, published a report recommending fundamental shifts in the regulation of Minnesota utilities in order to modernize the state's electric system.[106] The e21 Initiative report recommends several reforms, including establishing a multi-year performance-based regulatory framework (composed of a 5-year plan and a 15-year plan), creating a clear methodology for determining the value of grid services, and adjusting time-varying rates.[107] In June 2015, Minnesota enrolled several of the e21 Initiative proposals with legislation that included a requirement that utilities operating under multiyear rate plans that are approved by the Minnesota Public Utilities Commission to engage in distribution system planning and report and identify "investments considered necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of [advanced] two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies."[108]

- **New York.** The New York Public Service Commission's (NYPSC) proceeding on its Reforming the Energy Vision (REV) initiative continued to make progress over the last year. The REV proceeding is considering how to align electric utility practices and the state's regulatory framework with technological advances in information management, and power generation and distribution.[109] After receiving a straw proposal from the New

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[104] In the Matter, on the Commission's Own Motion to Commence a Proceeding to Implement the Provisions of Public Act 1609 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company, Order, Case No. U-17689, (MPSC June 30, 2015), available at http://efile.mpsc.state.mi.us/efile/docs/17689/0155.pdf; and In the Matter, on the Commission's Own Motion to Commence a Proceeding to Implement the Provisions of Public Act 1609 of 2014; MCL 460.11(3) et seq., with regard to DTE Electric Company, Opinion and Order, Case No. U-17689, (MPSC June 15, 2015), *available at* http://efile.mpsc.state.mi.us/efile/docs/17689/0148.pdf.

[105] In the Matter, on the Commission's Own Motion to Commence a Proceeding to Implement the Provisions of Public Act 1609 of 2014; MCL 460.11(3) et seq., with regard to Consumers Energy Company, Order, Case No. U-17688, (MPSC June 30, 2015) *available at* http://efile.mpsc.state.mi.us/efile/docs/17688/0158.pdf.

[106] *Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota*, e21 Initiative, (December 2014), p. ii, *available at* https://www.betterenergy.org/sites/www.betterenergy.org/files/e21_Initiative_Phase_I_Report_2014.pdf.

[107] *Id.* at 8-11.

[108] Minnesota State Legislature, 2015 Jobs and Energy Bill, H. F. No. 3, 89th Legislature, 2015 1st Special Session, Sec. 22. Minnesota Statutes 2014, section 216B.2425, *available at* http://www.house.leg.state.mn.us/bills/billnum.asp?Billnumber=HF0003&ls_year=89&sessionvar=20151.

[109] More information on the REV proceeding is *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument.

York Department of Public Service (NYDPS) staff, and then conducting public statement hearings, the NYPSC adopted a regulatory policy framework and implementation plan for the REV in February 2015.[110] A report from a Market Design and Platform Technology working group focused on technical issues associated with the creation of distributed system platforms was issued in July 8, 2015.[111] The report notes key considerations for the development of Distributed System Platform Provider (DSPP) technologies include cyber-security, assuring interoperability and consistency across DSPPs, and supporting future flexibility and scalability. A NYDPS staff white paper on changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with REV was released July 28, 2015.[112] Utility Distributed System Implementation Plans from each utility within the state are due by December 15, 2015.

In a related matter, in December 2014, the NYPSC approved Con Edison's proposed $200 million Brooklyn-Queens Demand Management (BQDM) Program, which seeks to procure 52 MW of non-traditional utility and customer-side demand reduction measures to defer approximately $1 billion of transmission and distribution infrastructure investments. The NYPSC considers the BQDM program an opportunity to understand the effects of the objectives laid out in the REV proceeding. Of the 52 MW, 41 MW are proposed to be customer-side measures, including demand response, energy efficiency, distributed energy storage, distributed generation, and other solutions that may be proposed by developers. The remaining 11 MW would come from utility-scale battery energy storage installed at existing substations. In an April 2015 order on rehearing, the NYPSC clarified that Con Edison will be allowed to own only the battery storage portions of the BQDM project, reiterating the policy laid out in the REV proceeding that allows utility ownership of distributed energy resources only under certain circumstances, in order to meet the "objective of developing [distributed energy resource] assets through competitive markets and risk-based capital rather than ratepayer funding."[113]

- **Pennsylvania.** In June 2015, the Pennsylvania Public Utilities Commission (PUC) established new energy efficiency and demand response program targets for the state's seven electric distribution companies, based on energy efficiency and demand response

[110] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-M-0101, (NY PSC Feb. 26, 2015), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d.

[111] Reforming the Energy Vision (REV), Working Group 2: Platform Technology Final Report & Appendices, *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/853a068321b1d9cb85257d100067b939/$FILE/WG%202_Platform%20Technology_Final%20Report%20&%20Appendices.pdf

[112] *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Staff White Paper on Ratemaking and Utility Business Models, Case 14-M-0101, (NY PSC July 28, 2015), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b48954621-2BE8-40A8-903E-41D2AD268798%7d

[113] *Order Granting Rehearing And Granting Clarification In Part*, Case 14-E-0302, (NY PSC Apr 20, 2015), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={568A2086-F5F1-42D8-8FAF-AE24ADE21586}.

potential studies conducted by an independent evaluator.[114] Under this third phase of Pennsylvania's Energy Efficiency & Conservation program, the electric distribution companies must, on average, reduce electricity consumption by approximately 4 percent over the period 2016 to 2021, against a 2010 baseline. The Pennsylvania PUC set a total peak demand reduction target of 425 MW for the electric distribution companies, net of projected commitments in PJM's capacity auctions.[115]

- **Rhode Island.** In a December 2014 order,[116] the Rhode Island Public Utilities Commission (RIPUC) approved National Grid's 2015-17 Energy Efficiency and System Reliability Procurement Plan, which states that National Grid will further incorporate analysis of "non-wires alternatives"[117] to traditional utility infrastructure into its transmission and distribution planning process. In an ongoing pilot program, National Grid is currently testing whether demand response, among other resources, can manage local distribution capacity requirements during peak periods.[118] Over the course of three years, National Grid intends to introduce new technologies, such as heat pumps, heat pump water heaters, and wi-fi enabled air conditioners, to the pilot's participating customers.

[114] *See* Demand Response Potential Pennsylvania - Final Report, February 25, 2015, available at http://www.puc.pa.gov/pcdocs/1345077.docx; and Energy Efficiency Potential Study for Pennsylvania – Final Report, February 2015, available at http://www.puc.pa.gov/pcdocs/1345079.pdf.

[115] *Act 129 Phase III EE&C Program Final Implementation Order*, Docket No. M-2014-2424864, (PA PUC Jun 11, 2015), pp. 35, 57, *available at* http://www.puc.pa.gov/pcdocs/1367313.doc.

[116] In Re: the Narragansett Electric Company d/b/a National Grid's 2015-2017 Energy Efficiency and System Reliability Procurement Plan, Order No. 21781, Docket No. 4522, (RIPUC Dec 19, 2014), *available at* http://www.ripuc.org/eventsactions/docket/4522-NGrid-Ord21781_12-19-14.pdf.

[117] Non-wires alternatives include demand response, energy efficiency, distributed generation, energy storage, volt VAR optimization, and dynamic pricing.

[118] National Grid, *National Grid 2015-2017 Energy Efficiency and System Reliability Procurement Plan*, Sept 2, 2014, in Docket No. 4522, *available at* http://www.ripuc.org/eventsactions/docket/4522-NGrid-EE-3-YrPlan(2015-2017)_%209-2-14.pdf.

Chapter 6: Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs

The 2009 National Assessment of Demand Response Potential[119] and previous annual reports describe the barriers to customer participation in demand response. The federal government and state and local governments continue to address outstanding barriers to demand response. Recent actions are presented below.

- **Implementing Time-based Pricing.** A limited number of customers participate in time-based pricing programs, which enable customers to better manage their electricity consumption and the associated costs. As noted earlier in this report, several state commissions have recently taken action requiring utilities in their states to implement time-based rate structures for their customers, partially based on the expectation that advanced metering infrastructure will be fully deployed in the near future. For example, the California Public Utilities Commission is requiring, among other things, that the three investor-owned utilities establish default time-of-use rates for residential customers starting in 2019. The Massachusetts Department of Public Utilities is likewise requiring as part of its broad grid modernization initiative that load serving entities in the state develop plans that, among other things, implement time varying rates for all rate classes following deployment of advanced meters. Similarly, the Michigan Public Service Commission recently ordered two utilities in the state to implement opt-in time-of-use and dynamic pricing rate structures over the next year or two.

- **Opportunities for Customer Education and Engagement.** As discussed above, as part of the Smart Grid Investment Grant Program, the U.S. Department of Energy (DOE) is partnering with ten utilities to conduct studies estimating the impact of several types of time-based rates, recruitment approaches (i.e., opt-in or opt-out), customer information systems (e.g., in-home displays), and customer automated control systems (e.g., programmable communicating thermostats) on peak demand, electricity consumption, and customer bills. The studies will provide new information for improving demand response program designs, implementation strategies, and evaluations, as well as facilitating customer education and overall program engagement. The most recent report[120] on the studies provides results based on interim evaluations from six utilities and interim and final evaluations from the remaining four utilities; major findings are summarized above in Chapter 5. The DOE plans to publish five more reports related to these consumer behavior studies between the third quarter of 2015 and the first quarter of 2016, when it will publish a final synthesis of all its findings.

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[119] Federal Energy Regulatory Commission, A National Assessment of Demand Response Potential, June 2009, *available at* http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[120] *See* U.S. DOE, Interim Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, June 2015, *available at* http://energy.gov/sites/prod/files/2015/06/f24/ARRA-CBS_interim_program_impact_report_June2015.pdf.

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