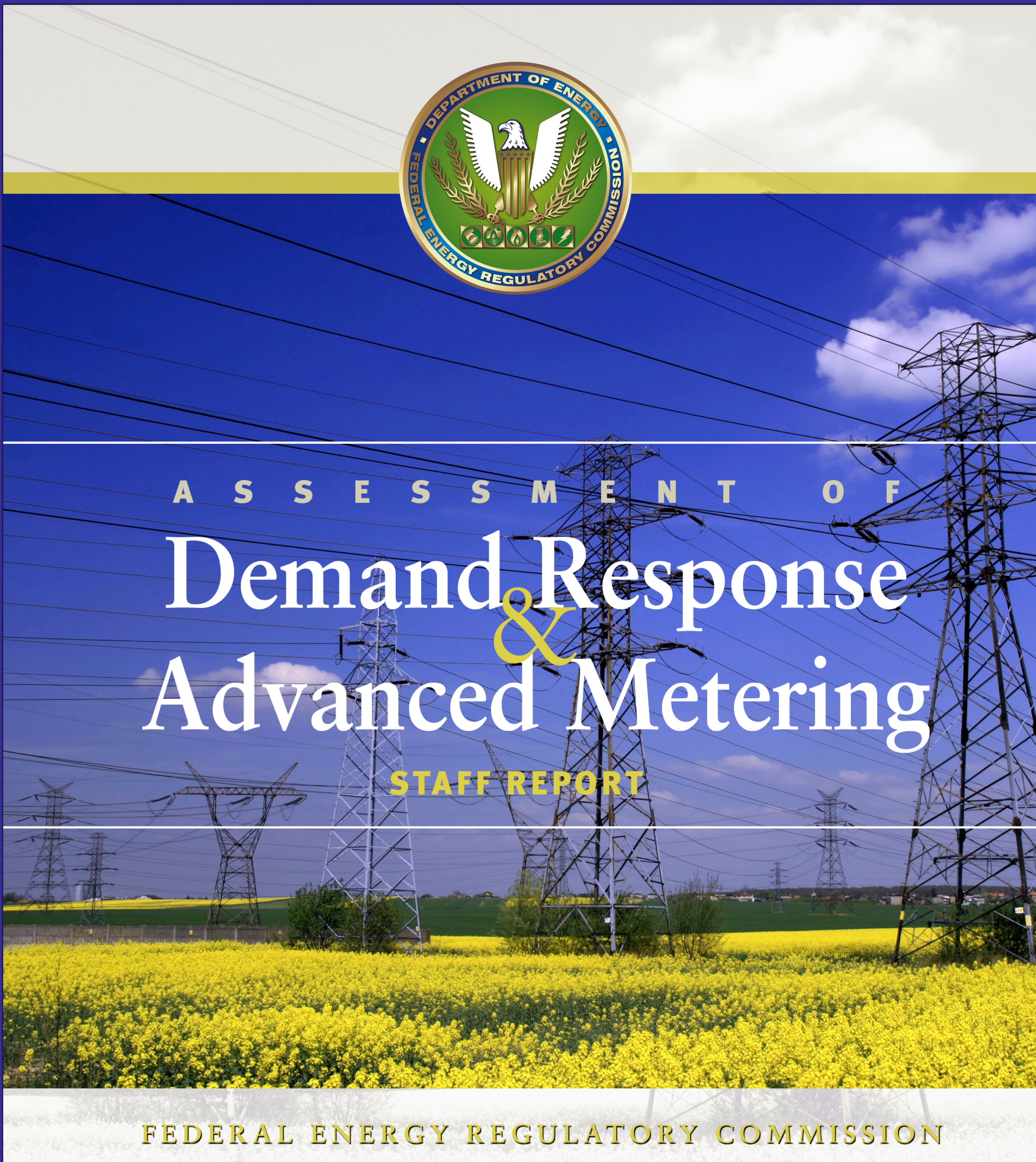

ASSESSMENT OF Demand Response & Advanced Metering

STAFF REPORT

FEDERAL ENERGY REGULATORY COMMISSION

DECEMBER 2014

2014

Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

December 2014

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

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TABLE OF CONTENTS

Chapter 1 : Introduction 1
Chapter 2 : Saturation and penetration rate of advanced meters 3
Developments and issues in advanced metering 5
Federal programmatic support for advanced meters 5
Demonstrated benefits of advanced meters 5
State legislative and regulatory activity 6
Chapter 3 : Annual resource contribution of demand resources 9
Role of Demand Response during Winter 2013/14 extreme weather events 12
Chapter 4 : The potential for demand response as a quantifiable, reliable resource for regional planning purposes 14
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 16
FERC demand response orders and activities 18
Other federal demand response activities 19
CEQ Presidential Memorandum on Energy Management 19
DOD and GSA activities 20
ERCOT activities 21
State legislative and regulatory activities related to demand response 21
Industry demand response actions 28
Chapter 6 : Regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs 29

LIST OF TABLES & FIGURES

Table 2-1: Estimates of Advanced Meter Penetration Rates 3
Table 2-2: Estimated Advanced Meter Penetration by Region and Customer Class (2012).......... 4
Table 3-1: Potential Peak Reduction from Retail Demand Response Programs by NERC Region (2011 & 2012).. 9
Table 3-2: Potential Peak Reduction (MW) from Retail Demand Response Programs by Region and Customer Class (2012).. 10
Table 3-3: Potential Peak Reduction from U.S. ISO and RTO Demand Response Programs 11
Table 5-1: Customer Enrollment in Incentive-based Demand Response Programs, by NERC Region (2011 & 2012) 17
Table 5-2: Customer Enrollment in Time-based Demand Response Programs, by NERC Region (2011 & 2012).. 18

FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

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

December 2014

Chapter 1: Introduction

This report is the Federal Energy Regulatory Commission staff's (Commission staff's) ninth annual report on demand response and advanced metering required by section 1252(e)(3) of 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:

- The penetration of advanced meters continues to climb.[1] According to the Energy Information Administration (EIA), an additional 5.9 million advanced meters were installed and operational between 2011 and 2012, resulting in advanced meters representing almost 30 percent of all meters in the United States;[2]
- Potential peak reduction from demand response in the Regional Transmission Organizations (RTOs), Independent System Operators (ISOs), and Electric Reliability Council of Texas (ERCOT) markets increased by 2,451 MW to 28,503 MW from 2012 to 2013 or 9.3 percent;[3] and,
- Demand response resources made significant contributions to balancing supply and demand during the late 2013 and early 2014 extreme cold weather events and helped preserve Eastern RTO and ISO reserve levels.[4]

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

[2] U.S. 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.

[3] *See infra* Table 3-3 (citing referenced data).

[4] See the section below titled "Role of Demand Response during Winter 2013/2014 extreme weather events," for a complete list of references.

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 saturation and penetration rates for advanced meters, as well as developments and issues in advanced metering through July 2013. As summarized in Table 2-1, recent data indicates that advanced meter penetration rates and the number of advanced meters in operation continue to increase in the United States.

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%

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. 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] U.S. 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).
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 2012 EIA data,[5] 43.2 million advanced meters were operational and there were 145.3 million ultimate electric utility customers,[6] indicating a 29.7 percent penetration rate. EIA data for the previous year reports 37.3 million advanced meters were operational out of a total of 144.5 million customers, representing a 25.8 percent penetration rate for 2011.[7] Certain industry organizations predict that use of advanced meters will continue to grow. For example, The

[5] U.S. EIA, *Electric Power sales, revenues, and energy efficiency Form EIA-861 data files*, (retail_sales_2012 and advanced_meters_2012 data files).

[6] Form EIA-861 collects data on the number of customers served by each respondent, which staff used as a proxy for the number of meters. EIA defines customers as the average of the 12 close-of-month customer accounts (*See* Form EIA-861 Instructions, General Instructions).

[7] U.S. EIA, *Electric Power sales, revenues, and energy efficiency Form EIA-861 data files* (2011 Data File 2 and File 8).

Edison Foundation's Institute for Electric Innovation projects more than half of all U.S. households will have advanced meters by 2015.[8]

Table 2-2 below provides estimated advanced metering penetration rates by North American Electric Reliability Council (NERC) region[9] and retail customer class.[10] Specifically, advanced meters represent more than half of the meters in three regions: 69.6 percent of meters in Texas Reliability Entity (TRE),[11] 52.3 percent in Florida Reliability Coordinating Council (FRCC), and 50.7 percent in Western Electricity Coordinating Council (WECC). A slightly higher percentage of residential customers have an advanced meter (30.4 percent) than do customers in the commercial (25.2 percent) or industrial (24.5 percent) classes.

Table 2-2: Estimated Advanced Meter Penetration by Region and Customer Class (2012)

	Customer Class			
NERC Region	Residential	Commercial	Industrial	All Classes
AK	1.3%	0.8%	0.0%	1.2%
FRCC	54.4%	36.6%	41.3%	52.3%
HI	0.0%	0.0%	4.1%	0.0%
MRO	14.3%	11.1%	17.9%	13.9%
NPCC	11.9%	11.9%	7.7%	11.9%
RFC	17.7%	13.6%	14.5%	17.3%
SERC	22.0%	17.6%	7.3%	21.4%
SPP	24.3%	21.4%	41.9%	24.2%
TRE	69.3%	73.0%	45.0%	69.6%
WECC	51.8%	43.6%	31.7%	50.7%
Unspecified	0.9%	0.3%	1.4%	0.8%
All Regions	**30.4%**	**25.2%**	**24.5%**	**29.7%**

Sources: U.S. EIA, 2012 Form EIA-861: advanced_meters_2012, utility_data_2012, and retail_sales_2012 data files.

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 includes short form respondents, some power marketers (excluding those in TX), unregulated entities and some federal entities. The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. Commission staff has not independently verified the accuracy of EIA data.

[8] Institute for Electric Innovation, *Powering the People: Next Generation Utility – Opening Animation* (video), (Mar. 6, 2014), *available at* http://www.edisonfoundation.net/iei/Pages/IEIHome.aspx

[9] NERC is comprised of eight regional reliability councils 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 and are separately presented for the report.

[10] Table 2-2 includes data from the 2012 Form EIA-861 long and short forms. *See* U.S. EIA, *Survey Forms: Electricity Survey Form Changes in 2013, available at* http://www.eia.gov/survey/changes/electricity/2013/

[11] To more accurately estimate advanced meter penetration in the TRE, power marketers in Texas that did not specify a NERC region have been assigned to the TRE.

Developments and issues in advanced metering

The American Recovery and Reinvestment Act of 2009 (Recovery Act),[12] through partnerships with more than 200 electric utilities and other organizations, accelerated the deployment of advanced meters throughout the nation's electric system.[13] Deployment of advance meters in the U.S. continues to progress as one component of electric grid modernization efforts. Industry stakeholders and policy makers are gaining experience with these new technologies, utilities are undertaking hardware and network integration efforts, and new grid and consumer applications are being explored and developed. Presented below are examples of continued programmatic support for advanced meters, reported demonstrated benefits of advanced meters, and state legislative and regulatory activities.

Federal programmatic support for advanced meters

As of March 31, 2014, approximately 15.3 million advanced meters were installed and operational through the Department of Energy (DOE) Smart Grid Investment Grant (SGIG) program.[14] Ultimately, 15.5 million advanced meters are expected to be installed and operational under SGIG. All SGIG projects are expected to reach completion in 2014 with continued reporting requirements through 2016.[15]

Demonstrated benefits of advanced meters

A majority of the public and privately supported Recovery Act projects fund installation of advanced metering infrastructure that provide electricity usage data on an hourly or sub-hourly basis, communications networks that transmit this meter data to the utility and back to customers, and the utility office management systems (such as meter data management systems) that receive, store, and process the meter data.[16] Advanced metering infrastructure facilitates several beneficial applications which can lead to improvements in operational efficiency, reliability and asset utilization. The applications include:

- Remote meter reading and remote connects/disconnects,
- Tamper detection and notification,
- Outage detection and notification,
- Voltage monitoring,

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[12] American Recovery and Reinvestment Act of 2009, Pub. L. No. 111-5 (2009). The Recovery Act appropriated $4.5 billion for grid modernization programs, with $3.4 billion of that amount devoted to the Smart Grid Investment Grant program, a public-private partnership initiative for leveraging investments in grid modernization.

[13] U.S. Department of Energy (DOE), *American Recovery and Reinvestment Act of 2009: Smart Grid Investment Grant Program, Progress Report II* at iv (Oct. 2013), *available at* https://www.smartgrid.gov/sites/default/files/doc/files/SGIG_progress_report_2013.pdf.

[14] U.S. DOE, SmartGrid.gov, Deployment Status: Advanced Metering Infrastructure and Customer Systems, https://www.smartgrid.gov/recovery_act/deployment_status. SGIG recipients reported approximately 16.2 million advanced meters physically installed as of July 10, 2014.

[15] *See Smart Grid Investment Grant Program, Progress Report II, supra* note 13 at iv.

[16] Id. at 19. Recovery Act funding resulted in the implementation of 131 smart grid projects representing over $9 billion in combined public and private investments under two programs: the SGIG program and the Smart Grid Demonstration Program (SGDP). Seventy four projects deploy advanced metering infrastructure.

- Enabling integration of distributed energy systems through net metering, and
- Enabling the application of time-based rates.

Several utilities have employed Recovery Act funding to initiate advanced metering projects which include technologies and systems designed to help customers better understand and manage their electricity consumption and costs. These technologies include direct load control devices, web portals (through which customers can access information via the Internet, in-home displays), and programmable communicating thermostats. In addition, as part of their respective Recovery Act funded projects, nine utilities are conducting eleven consumer behavior studies designed to evaluate the timing and magnitude of changes in peak demand and/or energy usage patterns through time-based rate programs, either in addition to, or as replacements for, traditional rates to further motivate customer demand response.[17] Demand-side objectives, achieved through advanced metering, customer systems, and time-based rates, can provide several benefits:[18]

- Deferred capital expenditures and improved capital asset utilization,
- Reduced electricity generation and environmental impacts, and
- Expanded options for customers to manage electricity consumption and costs.

Utilities are experimenting with different design techniques, such as randomized controlled trials, to improve their understanding of the magnitude of demand response, customer acceptance, and customer retention in various retail rate programs. Results indicate significant peak demand reductions, as well as bill savings for customers.[19]

State legislative and regulatory activity

- **Illinois.** In June 2014, Commonwealth Edison Company (ComEd) received approval from the Illinois Commerce Commission to accelerate the timetable for installing advanced meters.[20] ComEd will install more than four million advanced meters with full deployment expected by 2018, which is three years ahead of the originally publicized 2021 completion date.

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[17] U.S. DOE, *Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from SGIG Consumer Behavior Studies* at 4-5 (July 2013), *available at* https://www.smartgrid.gov/sites/default/files/doc/files/DOE_CBS_report_final_draft-7-10-13_0.pdf.

[18] U.S. DOE, *Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems – Initial Results* at ii (Dec. 2012), *available at* https://www.smartgrid.gov/sites/default/files/doc/files/peak_demand_report_final_12-13-2012.pdf

[19] Reports are accessible via Smartgrid.gov, which is available at https://smartgrid.gov. Additional material includes American Council for an Energy-Efficient Economy, *ACEEE Field Guide to Utility-Run Behavior Program*, Report No. B132, (Dec. 2013) Mazur-Stommen and Farley; *In Minnesota, 'behavior' programs show energy-saving results*, Midwest Energy News, July 23, 2014.

[20] Press Release, Commonwealth Edison Company (ComEd), ComEd Receives Approval to Accelerate Smart Meter Installation, Benefits, (June 11, 2014), *available at* https://www.comed.com/newsroom/Pages/newsroomreleases_06112014.pdf.

- **Maryland.** In February 2014, the Maryland Public Service Commission (Maryland PSC) issued an order setting customer opt-out fees and ruled that Baltimore Gas and Electric, Delmarva Power and Light Company, Potomac Electric Power Company, and Southern Maryland Electric Cooperative must give customers the opportunity to opt-out of an advanced meter.[21] In the order, the Maryland PSC states it was "cognizant of the costs imposed by extending this choice to individual ratepayers…[and would] allocate to these opt-out customers the appropriate costs associated with their choice[.]" Opt-out customers will be able to either keep their existing analog meter, or if a smart meter has already been installed, may have a non-smart digital meter installed instead.

- **Massachusetts.** In a June 2014 order, the Massachusetts Department of Public Utilities (DPU) established four grid modernization objectives for the distribution system in the state, including (1) reducing the effects of outages, (2) "optimizing demand" through time-based pricing and reducing peak demand, (3) integrating distributed resources, and (4) improving workforce and asset management. The order requires electric distribution companies to submit 10-year grid modernization plans that meet these objectives. Initial grid modernization plans must include, among other things, a five-year investment plan outlining how companies will implement "advanced metering functionality," which the DPU views as the technological foundation of the state's grid modernization goals.[22] The DPU also concluded that a targeted cost recovery framework is necessary for grid modernization investments to overcome barriers to such investment under traditional cost-of-service ratemaking. Specifically, utilities may request a capital expenditure tracking mechanism that speeds up cost recovery for advanced metering investments that "accelerate progress in achieving the grid modernization objectives."[23]

- **Missouri.** In February 2014, Missouri Public Service Commission (MPSC) staff updated the Missouri Smart Grid Report.[24] Among other things, staff recommends the opening of a new docket to address cost recovery issues and periodic workshops or technical conferences to share best practices.

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[21] *In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure*, Case Nos. 9207, 9208, and 9294, Order No. 86200, Maryland Public Service Commission (Feb. 26, 2014), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9207\\307.pdf.

[22] Advanced metering functionality means: (1) the real-time collection of customers' interval usage data, to enable participation in ISO-NE's energy and ancillary services markets; (2) automated notification of outages and restorations; (3) two-way communication between the utility and the customer; and (4) with a customer's permission, communication with and control of appliances. Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, D.P.U. 12-76-B, (Massachusetts Department of Public Utilities June 12, 2014), *available at* http://www.mass.gov/eea/docs/dpu/electric/12-76-a-order.pdf.

[23] *Id.* at 19-22.

[24] *Missouri Smart Grid Report*, File No. EW-2011-0175 (Missouri Public Service Commission Feb. 2014), *available at* http://psc.mo.gov/CMSInternetData/Electric/Missouri%20Smart%20Grid%20Report%20-%20February%202014.pdf.

- **Oregon.** Idaho Power Company[25], PacifiCorp[26] and Portland General Electric[27] submitted their 2014 smart grid and advanced metering reports with the Oregon Public Utilities Commission (OPUC) between June and October 2014. Most of Idaho Power's meters now have advanced metering capabilities and the company is applying these capabilities to enhance controls and services including remote connection and disconnection, direct load control, and time-variable pricing (which is available to qualifying residential customers through a pilot program).[28] PacificCorp expects to release its advanced metering solution for Oregon by the end of 2014 and is evaluating vendor proposals for advanced metering system implementation. Portland General Electric's Smart Grid Report, which was revised to include PUC recommendations and subsequently made effective by the Oregon PUC in October 2014,[29] includes smart grid initiatives to raise customer awareness, improve customer engagement, offer pricing options and partner with customers to reduce usage during critical system peaks.

[25] Idaho Power Company, Smart Grid Report, Docket No. UM 1675 (Oregon PUC Oct. 1, 2014), *available at* http://edocs.puc.state.or.us/efdocs/HAQ/um1675haq12121.pdf

[26] PacifiCorp, Smart Grid Annual Report, Docket No. UM 1667 (Oregon PUC Oct 31, 2014), *available at* http://edocs.puc.state.or.us/efdocs/HAQ/um1667haq163543.pdf.

[27] Portland General Electric, Smart Grid Report, Docket No. UM 1657 (Oregon PUC June 1, 2014) *available at* http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq162736.pdf.

[28] Idaho Power, Time of Day: Pilot Study Status Report, (June 20, 2013), *available at* https://www.idahopower.com/pdfs/AboutUs/CompanyInformation/SmartGrid/2013SmartGridReport.pdf; Idaho Power, Smart Grid Report for the Public Utility Commission of Oregon at app. D-6 (Oct. 1, 2013) *available at* http://edocs.puc.state.or.us/efdocs/HAA/um1675haa94950.pdf.

[29] In the Matter of Portland General Electric Company, Annual Smart Grid Report, Order No. 14333, (Oregon PUC Oct. 1, 2014), *available at* http://apps.puc.state.or.us/orders/2014ords/14-333.pdf

Chapter 3: Annual resource contribution of demand resources

This chapter summarizes the annual resource contribution of demand resources from retail demand response programs and RTO and ISO demand response programs on a national and regional basis in 2011 through 2013, and also discusses the role of demand response in certain regions of the country during extreme weather events. According to data collected by EIA, total U.S. potential peak reduction[30] from retail demand response programs increased by 1,907 MW between 2011 and 2012 (7.2 percent). Demand response programs within the Western Electricity Coordinating Council (WECC) accounted for 1,253 MW of potential peak reduction or nearly two-thirds (65.7 percent) of the increase in the U.S. total. Table 3-1 presents 2011 and 2012 potential peak reduction from retail demand response programs within each of the nine regional electricity councils, as well as Alaska and Hawaii.

Table 3-1: Potential Peak Reduction from Retail Demand Response Programs by NERC Region (2011 & 2012)

NERC Region	Annual Potential Peak Reduction (MW)		Year-on-Year Change	
	2011	2012	MW	%
AK	28	27	-1	-3.6%
FRCC	3,360	3,306	-54	-1.6%
HI	43	42	-1	-2.1%
MRO	5,450	5,567	117	2.1%
NPCC	613	606	-7	-1.2%
RFC	5,529	5,836	307	5.6%
SERC	5,937	6,046	109	1.8%
SPP	1,215	1,323	108	8.9%
TRE	340	480	140	41.3%
WECC	4,016	5,269	1,253	31.2%
Unspecified	63	0	-63	-100.0%
Total	**26,596**	**28,503**	**1,907**	**7.2%**

Sources: U.S. EIA, EIA-861 file3_2011, dsm_2012 and utility_data_2012 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.

Industrial customer demand response represents 47 percent of the 2012 national potential peak reduction from retail programs, but the relative contribution by customer class varies by region (Table 3-2). For example, in FRCC the majority (53 percent) of potential peak reduction from retail programs in the region came from residential customer demand response. In contrast,

[30] 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.

commercial customers accounted for the majority of potential peak reduction in Alaska, Hawaii, NPCC and TRE; and industrial customers accounted for the majority in MRO, RFC, SERC, SPP, and WECC. Overall, residential and commercial customer demand response account for 30 and 23 percent of the 2012 national potential peak reduction from retail programs, respectively.

Table 3-2: Potential Peak Reduction (MW) from Retail Demand Response Programs by Region and Customer Class (2012)

NERC Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	1,762	1,097	447	0	3,306
HI	17	25	0	0	42
MRO	1,869	1,141	2,557	0	5,567
NPCC	84	421	88	14	606
RFC	1,520	815	3,502	0	5,836
SERC	1,399	1,170	3,475	2	6,046
SPP	172	391	760	0	1,323
TRE	88	333	59	0	480
WECC	1,684	1,056	2,365	165	5,269
All Regions	**8,600**	**6,462**	**13,261**	**180**	**28,503**

Source: U.S. EIA, EIA-861 dsm_2012 and utility_data_2012 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.

As shown in Table 3-3, potential peak reduction from RTO and ISO demand response programs increased by 9.3 percent or 2,452 MW since 2012, to reach a total potential peak reduction of 28,798 MW in 2013. The potential peak reduction from customers participating in RTO and ISO programs also increased as a percentage of total peak demand, increasing from 5.6 percent of peak demand in 2012 to 6.1 percent in 2013.

Potential peak reduction increased by 2,600 MW in MISO from 2012 to 2013, largely due to increased demand response from behind-the-meter generation and load modifying resource programs run by utilities. This increase in demand response participation, coupled with a decline in peak demand in the region due to milder summer temperatures, resulted in potential peak reduction as a percentage of peak demand increasing by almost 3 percent in 2013, compared to 2012.[31]

[31] Potomac Economics, 2013 State of The Market Report for the MISO Electricity Markets at 6, 72 (June 2014), *available at* https://www.idahopower.com/pdfs/AboutUs/CompanyInformation/SmartGrid/2013SmartGridReport.pdf.

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

RTO/ISO	2012 Potential Peak Reduction (MW)	2012 Percent of Peak Demand[8]	2013 Potential Peak Reduction (MW)	2013 Percent of Peak Demand[8]
California ISO (CAISO)	2,430 [1]	5.2%	2,180 [9]	4.8%
Electric Reliability Council of Texas (ERCOT)	1,800 [2]	2.7%	1,950 [10]	2.9%
ISO New England, Inc. (ISO-NE)	2,769 [3]	10.7%	2,100 [11]	7.7%
Midcontinent Independent System Operator (MISO)	7,197 [4]	7.3%	9,797 [12]	10.2%
New York Independent System Operator (NYISO)	1,925 [5]	5.9%	1,307 [13]	3.8%
PJM Interconnection, LLC (PJM)	8,781 [6]	5.7%	9,901 [14]	6.3%
Southwest Power Pool, Inc. (SPP)	1,444 [7]	3.1%	1,563 [15]	3.5%
Total ISO/RTO	**26,346**	**5.6%**	**28,798**	**6.1%**

Sources:
[1] California ISO 2012 Annual Report on Market Issues and Performance
[2] ERCOT Quick Facts (Nov. 2012)
[3] 2012 Assessment of the ISO New England Electricity Markets
[4] 2012 State of the Market Report for the MISO Electricity Markets
[5] 2012 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan, 15, 2013). Figure includes ICAP/Special Case Resources (1,744 MW), Emergency DR (144 MW), and Day-Ahead Demand Response (37 MW)
[6] PJM 2012 Load Response Activity Report, Delivery Year 2012-2013 Active Participants in PJM Load Response Program at 2-3, (Apr. 9, 2013). Figure includes all resources registered as Emergency DR (8,552 MW), plus the difference between resources registered as Economic DR and both Emergency & Economic DR (229 MW)
[7] SPP Fast Facts (Mar. 1, 2013)
[8] Peak demand data are from the following: California ISO 2012 & 2013 Annual Reports on Market Issues and Performance; ERCOT 2013 Demand and Energy Report; ISO-NE Net Energy and Peak Load Report (Apr. 2013 & Apr. 2014); 2012 & 2013 State of the Market Reports for the MISO Electricity Markets; 2012 & 2013 State of the Market Reports for the New York ISO Markets; 2012 & 2013 PJM State of the Markets Reports, Vol. 2; SPP 2012 & 2013 State of the Market Reports
[9] CAISO 2013 Annual Report on Market Issues & Performance
[10] ERCOT Quick Facts (Nov. 2013) http://www.ercot.com/content/news/presentations/2013/ERCOT_Quick_Facts_November%202013.pdf
[11] ISO-NE Demand Response Asset Enrollments at 2, (Jan. 2014)
[12] 2013 State of the Market Report for the MISO Electricity Markets at 72. This figure excludes 366 MW of emergency demand response that is also classified as LMR
[13] 2013 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan. 15, 2014)
[14] PJM 2013 Demand Response Operations Markets Activity Report at 3-4 (Apr. 18, 2014), Figure represents "unique MW."
[15] SPP Fast Facts (as of Dec. 2013)

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

Potential peak reduction in several RTOs and ISOs declined from 2012 to 2013. For the New York ISO (NYISO) fewer demand response resources registered as Special Case Resources following NYISO's implementation of its baseline calculation and auditing methods. This may be attributable to changes in NYISO's methods that tightened criteria for qualification.

Relatively low capacity prices in NYISO in recent years may have also contributed to less participation in the SCR program.[32]

Demand response enrollments in ISO-NE declined by 669 MW—nearly 25 percent—in 2013. According to published reports and analyst comments, this decline may be at least partially due to Enernoc's reduced presence in the Forward Capacity Market based on its customers' view that participation requirements out-weigh the value of participation.[33] In CAISO, according to the market monitor's report, reductions in capacity in two of SCE's programs, while partially offset by an increase in capacity in PG&E's programs, led to an overall the decline in potential peak reduction by demand response in 2013.[34]

Role of Demand Response during Winter 2013/14 extreme weather events

The January 2014 cold weather events caused numerous challenges for electricity system operators. In the eastern United States, the extreme cold weather of January 6-8 and January 17-29 resulted in high demand, generation outages, and fuel disruptions that affected electric and fuel markets. Eastern RTO/ISO system operators utilized demand response during these high load periods to balance the electric system and prevent reserve shortages.

PJM activated about 2,000 MW of demand response for several hours during the morning and evening peaks of January 7th, and over 2,500 MW for several hours on January 23rd and January 28th.[35] PJM called on demand response to address issues with transfers, transmission limits and generating unit forced outages.[36] Although demand resources were not obligated to respond during this period, close to 25 percent of registered demand response resources responded. PJM states that this experience demonstrates the year-round value of demand response.[37]
As part of its 2013-2014 Winter Reliability Program, ISO-NE gained the ability to call on demand response assets up to 10 times during the winter. Demand response resources provided 21 MW on five occasions between December 2013 and February 2014.[38] ISO-NE included demand response as a component of its 2014-2015 Winter Reliability Program.[39]

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[32] Potomac Economics, 2013 State of the Market Report for the New York ISO Markets, at 91-93 (May 2014), *available at* http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013.shtml.

[33] Platts, Enernoc thinning position in New England forward capacity market, (Apr. 9, 2013), *available at* http://www.platts.com/latest-news/electric-power/washington/enernoc-thinning-position-in-new-england-forward-21928104; Analysis Group, Capacity Markets in the Northeast: A Preview of Comments at the FERC Technical Conference on Centralized Capacity Markets in RTOs/ISOs at 16, Tierney, (Sept. 20, 2013) *available at* http://www.ippny.org/uploads/PDF/1378921415_TierneyPresentation_Fall2013.pdf.

[34] California ISO, Dep't of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, (Apr. 2014), *available at* http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[35] FERC Office of Enforcement, Technical Conference on Winter 2013-2014 Operations and Market Performance in RTOs and ISOs, Tr. 21, (April 1, 2014).

[36] PJM, Analysis of Operational Events and Market Impacts during the January 2014 Cold Weather Events at 37, (May 8, 2014).

[37] *Id.* at 20-21.

[38] Letter from Gordon Van Welie, President, ISO-NE, to U.S. House Committee on Energy and Commerce, *ISO-New England* at 8 (April 18, 2014), *available at* http://www.iso-ne.com/pubs/pubcomm/corr/2014/2014-04-18-iso-ne-response-to-house-energy-commerce.pdf.

[39] *ISO New England, Inc.*, 148 FERC ¶ 61,179, at PP 17-18, 39 (2014).

Other RTOs also utilized demand response during the winter peak load periods. NYISO has an Emergency Demand Response Program and a Special Case Resources capacity market program available for activation in energy shortage situations.[40] Both programs were activated on January 7, 2014 and NYISO called on reductions from about 900 MW of its demand resources.[41] Demand response resources were put on notice for the New York City zone on January 27th for activation on January 28th, but ultimately were not needed to maintain reserve requirements.[42]

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[40] New York ISO, Demand Response Programs, *available at* http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp

[41] *See*: FERC Office of Enforcement, Technical Conference on Winter 2013-2014 Operations and Market Performance in RTOs and ISOs (April 1, 2014), Transcript at 21; New York State Reliability Council, *NYISO Operations Report*, (January 2014), *available at* http://www.nysrc.org/pdf/MeetingMaterial/RCMSMeetingMaterial/RCMS%20Agenda%20170/January%202014%20Ops%20Report.pdf.

[42] Wes Yeomans, NYISO, Presentation at Technical Conference on Winter 2013-2014 Operations and Market Performance in RTOs and ISOs (April 1, 2014).

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

This chapter reports on the potential for demand response as a quantifiable, reliable resource for planning. The Department of Energy's (DOE) Interconnection-wide Transmission Planning Initiative facilitated collaborative efforts to develop interconnection-wide transmission plans for the Western Interconnection, the Eastern Interconnection, and ERCOT under a broad set of alternative futures, including the intensive application of demand-side technologies.[43] Funded by DOE grants, five organizations undertook efforts in the Western, Eastern and Texas Interconnections: Western Electricity Coordinating Council (WECC), Western Governors Association, the Eastern Interconnection Planning Collaborative (EIPC), the Eastern Interconnection States' Planning Council (EISPC), and ERCOT. After the completion of initial transmission planning efforts, these organizations continue to undertake enhanced studies of long-term interconnection-wide needs.

WECC, the Western Governors' Association, and the Western Interstate Energy Board are working with stakeholders through the Regional Transmission Expansion Project to develop long-term, interconnection-wide transmission expansion plans.[44] The Western Interstate Energy Board, along with the State-Provincial Steering Committee,[45] released a report examining advanced demand response (i.e., "DR 2.0") as a resource for integrating variable energy resources.[46] Advanced demand response resources are customer loads equipped with automation equipment that can increase and decrease while being available throughout the year and frequently measured. The report focuses on the extent demand response resources can complement variable energy resources within a three to five year time frame and provides various estimates of the aggregate potential peak reduction from demand response for the Western Interconnection's eleven states and two Canadian provinces.

EISPC and National Association of Regulatory Utility Commissioners (NARUC) are also providing general information to policy makers examining the use of planning models that not only compare transmission-only or generation-only solutions, but also integrate demand response and non-traditional resources to provide "more balanced and economic" resource mixes with fuel and environmental benefits.[47] EISPC and NARUC discuss demand response modeling and data

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

[44] Western Governors' Association, *Regional Transmission Expansion Planning, available at* http://www.westgov.org/index.php?option=com_content&view=article&id=311&Itemid=81

[45] SPSC was established in 2009 to execute the Recovery Act grant on interconnection-wide transmission planning and was charged with providing input into transmission planning, improving grid utilization, and reducing the cost of integrating renewable energy resources. Minutes of the June 13, 2013 Meeting of the Western Interstate Energy Board, *available at* http://www.westgov.org/wieb/meetings/boardsprg2013/minutes.pdf.

[46] Western Interstate Energy Board, *The Role of Demand Response in Integrating Variable Energy Resource*, (December 2013), *available at* http://www.westernenergyboard.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf.

[47] EIPC and NARUC, Co-optimization of Transmission and Other Supply Resources at 4, (September 2013), *available at* http://www.westernenergyboard.org/sptsc/documents/12-20-13SPSC_EnerNOC.pdf.

preparation requirements and the pros and cons associated with integrating various demand side and non-traditional resource options.[48]

ERCOT, in December 2013, released an expanded 20-year system assessment of the Texas Interconnect.[49] Three different forecasts were created to support study scenarios: business-as-usual scenario, drought, and an energy efficiency mandate.[50] In the ERCOT forecasts, various levels of demand response resources are modeled in future years to plan for various system conditions.[51]

The Commission's Order No. 1000 requires public utility transmission providers to comparably consider transmission and non-transmission alternatives—such as energy efficiency, demand response, energy storage, distributed generation, and combined heat and power systems sited close to load—in the regional transmission planning process.[52] Some regions in their Order No. 1000 compliance planning processes have taken steps towards formalizing the consideration of non-transmission alternatives. For example, NYISO considers all resource types – including generation, transmission, demand response, or a combination of these resource types – on a comparable basis when evaluating proposed solutions in their regional transmission planning process. In addition, several regional transmission organizations, such as PJM, consider demand response and other non-transmission alternatives prior to determining what transmission projects to consider in their transmission planning process. PJM also allows demand response to participate in its capacity market and produce firm commitments to meet its capacity needs. On August 15, 2014, U.S. Court of Appeals for the D.C. Circuit issued its decision in *South Carolina Public Service Authority v. FERC* fully affirming Order No. 1000.[53]

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[48] *Id.* at 50.

[49] ERCOT Interconnection, *Long-Term Transmission Analysis (2012-2032) Final Report, Topic A and B Final Report, Volumes 1*, at vi, 32 (December 2013), *available at* http://www.ercot.com/content/committees/other/lts/keydocs/2014/DOE_LONG_TERM_STUDY_-_Final_Report_-_Volume_1.pdf.

[50] *Id.* at 43.

[51] *Id.* app. H (Generation Expansion Summaries).

[52] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (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).

[53] No. 12-1232 (D.C. Cir., Aug. 15, 2014).

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 2011 and 2012, and summarizes recent federal, regional, state, and industry demand response actions. Tables 5-1 and 5-2 show customer enrollment in incentive-based[54] and time-based[55] demand response programs in 2011 and 2012. As shown in Table 5-1, at a national level, the number of customers enrolled in incentive-based programs increased by 1.2 percent over this period, to more than 5.4 million. On a regional basis, the year-on-year changes ranged from a decline of 18 percent to an increase of 64 percent.

For example, according to EIA data, customer enrollment increased by nearly 64 percent in TRE from 2011 to 2012, due to large increases in enrollment in residential programs run by Centerpoint Energy and the City of San Antonio. In contrast, customer enrollment in incentive-based programs fell by approximately 18 percent in SPP over the same period due to a drop in enrollment in several existing programs (e.g., Kansas Gas & Electric and Public Service Co. of Oklahoma), and the discontinuation of a residential program at North Arkansas Electric Coop.

The largest absolute change in incentive-based program enrollment occurred in RFC, where the introduction of new programs in 2012 by some utilities (e.g., Metropolitan Edison Co., PEPCO, Northern Indiana Public Service Co.) and increased enrollment in other utilities' existing programs (e.g., PPL), was more than offset by the discontinuation of programs by some utilities and large drops in enrollment in other utilities' existing residential programs (e.g., BGE, Duke Indiana, and Jersey Central Power & Light).

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

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

Table 5-1: Customer Enrollment in Incentive-based Demand Response Programs, by NERC Region (2011 & 2012)

NERC Region	Enrollment in Incentive-based Programs		Year-on-Year Change	
	2011	2012	Customers	%
AK	2,460	2,432	-28	-1.1%
FRCC	1,283,904	1,328,487	44,583	3.5%
HI	37,304	36,703	-601	-1.6%
MRO	714,669	795,345	80,676	11.3%
NPCC	46,368	54,413	8,045	17.4%
RFC	1,546,608	1,398,341	-148,267	-9.6%
SERC	652,940	715,225	62,285	9.6%
SPP	112,041	91,585	-20,456	-18.3%
TRE	67,113	109,875	42,762	63.7%
WECC	903,063	884,299	-18,764	-2.1%
Unspecified	0	15,004	15,004	--
Total	**5,366,470**	**5,431,709**	**65,239**	**1.2%**

Sources: U.S. EIA, EIA-861 file3_2011, EIA-861 dsm_2012 and utility_data_2012 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 shows, in contrast to incentive-based demand response programs, nationwide enrollment in time-based programs declined 6.1 percent from 2011 to 2012, although there was again much regional variation. According to EIA data, the large percentage change in enrollment in the "unspecified" region is due to increased enrollment in a residential program run by TXU Energy, a retail power marketer.[56] WECC also experienced a large absolute and percentage change in enrollment, primarily due to creation of new programs by San Diego Gas & Electric, Sacramento Municipal Utility District, Los Angeles Department of Water and Power, and Arizona Public Service.

In addition, according to EIA data, SPP and RFC experienced significant absolute and percentage drops in enrollment in time-based programs. In SPP, this was due to the discontinuation of programs by Southwestern Electric Power and a large decline in enrollment in programs run by Public Service Co. of Oklahoma. In RFC, EIA data suggests the decline in enrollment was primarily due to attrition in Ohio Power's residential program and in Duke Energy Indiana's commercial program.

[56] Power marketers are not required to specify a NERC region when responding to the EIA-861 survey. U.S. EIA, Form EIA-861, Schedule 2, Part A.

Table 5-2: Customer Enrollment in Time-based Demand Response Programs, by NERC Region (2011 & 2012)

NERC Region	Enrollment in Time-based Programs		Year-on-Year Change	
	2011	2012	Customers	%
AK	0	38	38	--
FRCC	26,572	27,089	517	1.9%
HI	210	323	113	53.8%
MRO	76,921	82,310	5,389	7.0%
NPCC	244,837	293,721	48,884	20.0%
RFC	1,133,120	433,879	-699,241	-61.7%
SERC	180,507	180,619	112	0.1%
SPP	1,059,504	61,618	-997,886	-94.2%
TRE	669	604	-65	-9.7%
WECC	1,254,812	2,601,112	1,346,300	107.3%
Unspecified	3,844	57,435	53,591	1,394.1%
Total	**3,980,996**	**3,738,748**	**-242,248**	**-6.1%**

Sources: U.S. EIA, 2011: EIA-861 file3_2011; 2012: EIA-861 dsm_2012 and utility_data_2012 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), 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)). After denying petitions for rehearing en banc of the decision, on October 20, 2014, the D.C. Circuit granted FERC's motion to stay the issuance of the mandate until December 16, 2014, or if a petition for writ of certiorari is filed, until the Supreme Court's final disposition.[57] On December 5, 2014, the Solicitor General at the U.S. Department of Justice announced that he has authorized the filing of a petition for a writ of certiorari seeking review of the decision by the U.S. Supreme Court.

Prior to the decision in *Electric Power Supply Association v. FERC*, the Commission responded to a number of regional filings related to the participation of demand response resources in wholesale and interstate markets. This section briefly summarizes those Commission decisions.

[57] *EPSA v. FERC*, No. 11-1486 (D.C. Cir. Oct. 20, 2014) (order granting motion to stay issuance of mandate).

- **PJM Interconnection.** In an order issued May 9, 2014,[58] the Commission accepted PJM revisions to its tariffs to enhance the "operational flexibility" of demand response resources that clear its capacity market.[59] Among other things, the revisions are intended to make it easier for PJM to use demand response resources with a capacity supply obligation when approaching system emergencies.[60]

- **Midcontinent Independent System Operator.** In an order issued March 14, 2014,[61] the Commission accepted a MISO proposal to revise how demand response and energy efficiency is credited as part of MISO's resource adequacy requirements. Load serving entities (LSEs) meet their planning reserve margin requirement in the MISO region by demonstrating that enough capacity has been acquired to meet their respective coincident peak demand forecasts, plus transmission losses, plus the Planning Reserve Margin. Prior to the change, LSEs had the ability to net demand response and energy efficiency resources from coincident peak demand. In order to address problems associated with tracking and assigning demand response and energy efficiency resources when customers switch LSEs during a planning year, MISO will now require LSEs to explicitly account for demand response and energy efficiency resources as capacity in the same manner as all other Planning Resources.

- **New York Independent System Operator.** On November 22, 2013, the Commission issued an order finding NYISO's tariff provisions that excluded demand response facilitated by behind-the-meter generation from participation in the Day-Ahead Demand Response Program (DADRP), while permitting participation by similarly-situated demand response accomplished without the use of such behind-the-meter generation, were unduly discriminatory. The Commission ordered NYISO to develop rules that address appropriate eligibility, measurement, verification, and control requirements to ensure that demand response facilitated by behind-the-meter generation is provided in a manner that maintains system reliability and ensures that the resources are compensated only for the demand response service that they actually provide. Requests for rehearing, and action on NYISO's compliance filings, are pending.

Other federal demand response activities

CEQ Presidential Memorandum on Energy Management

On December 5, 2013, President Obama released the Presidential Memorandum on Federal Leadership on Energy Management.[62] This Presidential Memorandum directs federal agencies

[58] PJM Interconnection, L.L.C., 147 FERC ¶ 61,103 (2014).

[59] PJM Filing, Docket No. ER14-822-000 (filed December 24, 2013) (revising PJM OATT, OA & RAA with respect to Demand Response as a Capacity Resource).

[60] There are outstanding compliance issues and other issues subject to rehearing in this preceding.

[61] Midcontinent Indep. Sys. Operator, Inc., 146 FERC ¶ 61,180 (2014).

[62] The White House, *Presidential Memorandum – Federal Leadership on Energy Management: Memorandum for the Heads of Executive Departments and Agencies* (Dec. 5, 2013), *available at* http://www.whitehouse.gov/the-press-office/2013/12/05/presidential-memorandum-federal-leadership-energy-management.

to increase their use of renewable energy and to implement several innovative energy management practices. Specific federal agency directives in the Memorandum include: (a) requiring agencies to consume 20 percent of their total agency electricity consumption by 2020 from renewable sources; (b) completion of the installation of building energy meters and sub-meters as required by the National Energy Conservation Policy Act; (c) installation of water meters at agency buildings where cost-effective and appropriate; (d) directing that agency performance benchmarking conducted with the EPA Energy Star Portfolio Manager; (e) public disclosure of annual benchmark energy performance data through the Department of Energy web-based tracking system; (f) incorporation, where feasible, of the Green Button data standard into reporting, data analytics and automation, and processes, in consultation with local utilities; and (g) consideration of participation in demand response programs where available. These directives should update agency building-performance and energy-management practices to encourage increased energy efficiency and demand responsiveness.

DOD and GSA activities

In part because of the size of its infrastructure size and wide diversity of building types, the Department of Defense (DOD) recognizes it is "in a unique position to play a significant role in the development and deployment of the next generation of energy technologies."[63] DOD manages more than 300,000 buildings on some 500 installations throughout the United States,[64] and consumes more than three-quarters of the energy used by the federal government.[65] DOD's Strategic Environmental Research and Development Program (SERDP) and Environmental Security Technology Certification Program (ESTCP)[66] continue to support demonstration projects to facilitate DOD's participation in wholesale demand response programs.[67]

The U.S. General Services Administration (GSA) owns and leases over 9,600 federal buildings, including an inventory of more than 370 million rentable square feet of workspace,[68] and over 30 federal agencies rely on the GSA to help with energy procurement strategies.[69] In February 2014, GSA noted that its partnership with the curtailment service provider, NuEnergen, resulted

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[63] U.S. Dep't of Defense (DOD), Strategic Environmental Research and Development Program (SERDP) and Environmental Security Technology Certification Program (ESTCP), *Energy*, *available at* http://www.serdp-estcp.org/

[64] DOD, SERDP and ESTCP, *Energy and Water*, *available at* http://www.serdp-estcp.org/

[65] DOD, SERDP and ESTCP, *Energy and Water*; DOD, SERDP and ESTCP, *Energy*.

[66] DOD, SERDP and ESTCP, *About SERDP and ESTCP, available at* http://www.serdp-estcp.org/About-SERDP-and-ESTCP. SERDP invests in basic and applied research and advanced development; ESTCP identifies and demonstrates cost-effective technologies.

[67] SERDP and ESTCP projects include *Automated Demand Response for Energy Sustainability (EW-201256)*, *Demonstrating Enhanced Demand Response Program Participation for Naval District Washington (EW-201343)*, and *Market Aware High Performance Buildings Participating in Fast Load Response Utility Programs with a Single Open Standard Methodology (EW-201401)*. SERDP and ESTCP maintain a database of active and completed energy projects that is available at http://www.serdp-estcp.org/Program-Areas/Energy-and-Water/Energy/(list)/1/.

[68] U.S. General Services Admin. (GSA), *Review of the President's Climate Action Plan, Senate Committee on Environment and Public Works* (Jan. 16, 2014) *available at* http://www.gsa.gov/portal/content/184679.

[69] Press Release, WorldEnergy, GSA Awards World Energy 5-Year Energy Management Contract (Sept. 8, 2010), *available at* http://www.worldenergy.com/news/gsa-awards-world-energy-5-year-energy-management-contract/.

in the enrollment of 19 federal buildings in NYISO and PJM demand response programs. In 2013, GSA realized its largest demand response rebates.[70]

The U.S. Agriculture Department (USDA) continues to assist rural electric utilities with infrastructure upgrades, including smart grid investments, through the Rural Utilities Service Program. Since the fall of 2013, the USDA has announced a series of loans that include more than $65 million for smart grid projects to improve rural electric system communications technology.[71] Since 2011, the USDA has invested more than $580 million in smart grid technologies nationwide.[72]

ERCOT activities

ERCOT established a program on June 1, 2014 that enables specific loads from the residential and small commercial sectors to participate and be economically dispatched within the real-time energy market.[73] ERCOT also launched the Weather-Sensitive Emergency Response Service (ERS),[74] which allows aggregations of residential and other weather-sensitive consumers to offer demand response capabilities during summer month peak hours in exchange for a capacity payment.[75] The Weather-Sensitive ERS program has enrolled more than 60,000 accounts and is expected to provide as much as 21.6 MW of capacity. Additionally, ERCOT surveyed the number of retail customers in the ERCOT region subject to retail price response/demand response products to quantify expected demand reductions from these retail programs and products during various ERCOT events.[76]

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 2013 report. These developments suggest that many states consider demand

[70] Press Release, GSA, Region 2 Facilities Again Earn Largest Demand Response Rebate (Feb. 14, 2014), *available at* http://www.gsa.gov/portal/content/186379.

[71] Press Releases, U.S. Depart. of Agriculture (USDA), Rural Development, Utilities, (*See* September 5, 2013, September 12, 2013, October 24, 2013, December 13, 2013, and May 5, 2014), *available at* http://www.rurdev.usda.gov/NR_Utilities_LP.html.

[72] Press Release, USDA, Agriculture Secretary Announces Electric System Improvements in Eight States, (September 5, 2013), *available at* http://www.usda.gov/wps/portal/usda/usdahome?contentid=2013/09/0170.xml. The 2013 and 2014 USDA press releases announce over $54 million in subsequent funding.

[73] Paul Wattles, ERCOT Senior Analyst, Board of Directors Meeting, Item 9: Demand Response Update, (Aug. 12, 2014), *available at* http://www.ercot.com/content/meetings/board/keydocs/2014/0812/9_Demand_Response_Update.pdf.

[74] Press Release, ERCOT, As programs mature, ERCOT evaluates impact of demand-response services (Aug. 13, 2014), *available at* http://www.ercot.com/news/press_releases/show/26654.

[75] ERCOT, Governing Document for Weather-Sensitive Emergency Response Service Pilot Project (undated), *available at* http://www.ercot.com/content/mktrules/pilots/wsers/Weather_Sensitive_ERS_Governing_Document_(Board_Approved)1.doc.

[76] Frontier Associates, Results from the 2013 Survey of LSEs to Obtain Retail DR and Dynamic Pricing Information, ERCOT Demand-Side Working Group presentation (June 25 2014), *available at* http://www.ercot.com/calendar/2014/06/20140625-DSWG.

response an important resource in meeting state policy goals related to modernization of the grid and the electric industry.

- **California.** In a September 2013 Order Instituting Rulemaking, the California Public Utilities Commission (CPUC) launched a proceeding to consider several changes to demand response programs in the state, including dividing current utility demand response programs into demand-side and supply-side resources, creating a competitive procurement mechanism for supply-side demand response resources, and determining funding and procurement processes for programs. The CPUC notes that "bifurcating" existing demand response programs would enable providers to competitively bid supply-side demand response resources into the CAISO wholesale markets, allowing CAISO to see and dispatch these resources as other generation resources are dispatched. The rulemaking also proposes three pilot programs to test the integration of retail demand response into the CAISO markets.[77] The CPUC is addressing each of the issues raised in the September 2013 order separately.[78]

  The CPUC is also working with CAISO and the California Energy Commission (CEC) to create a market for demand response and energy efficiency resources.[79] CAISO advises that almost all of California's current demand response consists of load management programs operated by the state's three investor-owned utilities and overseen by the CPUC.[80] Demand response resources currently meet about five percent of CAISO's total system resource adequacy capacity requirements.[81]

  The CPUC, CAISO and CEC are developing a cross-agency work plan to align and track progress in four areas through 2020: load reshaping, resource sufficiency, operations and monitoring.[82] A 2014 objective is for CPUC, CAISO and CEC to reach consensus on a process to track the development of the state's demand response and energy efficiency

[77] *Order Instituting Rulemaking To Enhance The Role Of Demand Response In Meeting The State's Resource Planning Needs And Operational Requirements*, Rulemaking 13-09-011, (CPUC Sept. 25, 2013), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M077/K151/77151993.PDF.

[78] *Decision Addressing Foundational Issue of the Bifurcation Of Demand Response Programs*, Decision 14-03-026, (CPUC Apr. 4, 2014), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K480/89480849.PDF; *Decision Approving Two-Year Bridge Funding For Demand Response Programs*, Decision 14-01-004, (CPUC Jan. 16, 2014) *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K608/86608147.PDF. *Decision Approving Demand Response Program Improvements and 2015-2016 Bridge Funding Budget*, Decision 14-05-025, (CPUC May 15, 2014), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M091/K392/91392798.PDF; *Proposed Decision Resolving Several Phase Two Issues and Addressing The Motion for Adoption of Settlement Agreement on Phase Three Issues*, (CPUC Oct. 28, 2014) *available at* http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M129/K396/129396744.PDF.

[79] California ISO, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources* at 2 (Dec. 2013), *available at* http://www.caiso.com/documents/dr-eeroadmap.pdf.

[80] California ISO, Department of Market Monitoring, 2013 Annual Report on Market Issues & Performance at 32 (Apr. 2014), *available at* http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf.

[81] *Id.*

[82] California ISO, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources* (Dec. 2013).

resources.[83] Current CAISO efforts include developing approaches for conveying signals to customers to elicit beneficial shifts in energy consumption, work with stakeholders to consider these resources as alternatives to local transmission upgrades or power plant development, and working with the CPUC and CEC to establish a clear classification of each demand response program type as either a load-modifier or a supply-side resource.[84]

- **Hawaii.** In April 2014, the Hawaii Public Utilities Commission (HI PUC) released four orders that "provide major policy, resource planning, and operational directives to the Hawaiian Electric Company (HECO)" and strategic guidance for modernizing the electric system in the state.[85] One of the orders rejected HECO's proposed Integrated Resource Plan, finding that, among other things, the plan consisted of a series of unrelated projects without a strategy for moving toward a more sustainable business model. In a white paper attached to the order, the HI PUC lays out its vision of the future of Hawaii's electric utilities. In the HI PUC's view, the state has "entered a new paradigm" in which the best way to deliver least-cost electricity, expand customer options, and meet state policy goals is to aggressively pursue new clean energy sources, including utility-scale renewables, distributed generation, and demand response. Among the many recommendations in the report, the HI PUC states that HECO should implement an advanced metering program that focuses on delivering immediate value to customers by enabling them to access energy consumption data and to install distributed energy resources, including broader use of demand response technologies. The HI PUC also notes that, going forward, it will require Hawaii's electric utilities to employ demand response technologies and dynamic pricing structures to manage customer loads in real time.[86]

  In a related order, the HI PUC found that HECO's current demand response programs in the state are uncoordinated and do not fully capture the benefits of demand response. The HI PUC ordered HECO (and its subsidiaries) to establish comprehensive goals and performance metrics for demand response programs, and to consolidate existing and planned programs into an integrated portfolio. The HI PUC specified objectives HECO must incorporate into its program design, such as providing quantifiable benefits to ratepayers, reducing energy consumption and peak demand, mitigating the variability of renewable generators, assuring system reliability, providing ancillary services, and giving

[83] *Id.* at 21

[84] *Id.* at 8, 11, 13.

[85] Press Conference, Gov. Neil Abercrombie and Hawaii Public Utilities Commission (HI PUC), Announcement of Decisions Relating to Energy Policy in Hawaii, (Apr. 29, 2014) *available at* http://www.youtube.com/watch?v=MeHmZ6E5GhM&index=3&list=PLS0iu_gsq8HspYCWpCSi1rXiBUMnY1S2; Press Release, "PUC Orders Action Plans to Achieve State's Energy Goals," (HI PUC Apr. 29, 2014), *available at* http://puc.hawaii.gov/news-release/puc-orders-action-plans-to-achieve-states-energy-goals/.

[86] *Regarding Integrated Resource Planning*, Decision and Order No. 32052, Docket No. 2012-0036, (HI PUC Apr. 28, 2014), Ex. A, *available at* http://puc.hawaii.gov/wp-content/uploads/2014/04/Decision-and-Order-No.-32052.pdf.

customers greater control over their energy use.[87] Pursuant to the HI PUC order, HECO filed its Integrated Demand Resource Portfolio Plan on July 28, 2014.[88]

- **Maryland.** Some utilities in Maryland are in the process of rolling out dynamic pricing programs. In the summer of 2013, Baltimore Gas and Electric (BGE) delivered its new Smart Energy Rewards program to 315,000 customers with advanced meters. The program provides a rebate for reducing energy use during times of highest demand along with personalized energy savings tips, communication through multiple channels, immediate feedback on individual results, and comparisons with similar households. BGE plans to roll out the program to all of its 1.1 million residential customers by summer 2015.[89] In addition, the Maryland Public Service Commission approved Delmarva Power and Light's request[90] to phase in, and recover the costs of, a dynamic pricing program for residential customers, beginning in June 2014.[91]

- **Massachusetts.** In January 2014, the Massachusetts Department of Public Utilities (MA DPU) opened an investigation to examine how to implement time-varying rates, asking for stakeholder comment on, among other things, whether basic service and distribution rates should become or include time-varying rates.[92] In June 2014, the MA DPU issued an order proposing a framework for time-varying rates, concluding that such rates are essential to meeting the state's grid modernization goals and supporting state energy and environmental policies. Under the proposed framework, electric distribution companies in the state would be required to offer two time varying rates as their basic service products to all rate classes: (1) default time of use pricing with a critical peak pricing component, and (2) an option for a flat rate with a peak time rebate.[93] In a

[87] *Policy Statement and Order Regarding Demand Response Programs*, Order No. 32054, Docket No. 2007-0341, (HI PUC April 28, 2014) *available at* http://puc.hawaii.gov/wp-content/uploads/2014/04/Order-No.-32054.pdf.

[88] *Integrated Demand Response Portfolio Plan*, Docket No. 2007-0341, (HECO July 28, 2014) *available at* http://dms.puc.hawaii.gov/dms/OpenDocServlet?RT=&document_id=91+3+ICM4+LSDB15+PC_DocketReport59+26+A1001001A14G29B04851H0000418+A14G29B32630J102051+14+1960.

[89] Press Release, Opower, How Baltimore Gas and Electric is Solving the Dynamic Pricing Puzzle (Jan. 13, 2014), *available at* http://blog.opower.com/2014/01/how-baltimore-gas-and-electric-is-solving-the-dynamic-pricing-puzzle/.

[90] Delmarva Power & Light, Delmarva Power & Light Company's Proposed Phase-In Of Residential Dynamic Pricing Beginning June 1, 2014, Case No. 9207, (filed Mar. 14, 2014), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9207\\309.pdf.

[91] Letter to Parties noting that it has accepted tariff pages filed by DP&L - 5/7/14 AM, Case No. 9207, (MD PUC May 8, 2014), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9200-9299\9207\\318.pdf.

[92] Investigation by the Department of Public Utilities upon its own motion into Time Varying Rates, Order Opening Investigation, D.P.U. 14-04, (MA DPU Jan. 23, 2014), *available at* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-04%2f12314dpuord.pdf.

[93] Anticipated Policy Framework for Time Varying Rates, D.P.U. 14-04-B, (MA DPU June 12, 2014), *available at* http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf. As of this writing, the MA DPU is seeking comments on this proposed framework.

November 5, 2014 order, the MA DPU adopted without modification the proposed policy framework for the implementation of time-varying rates for basic service.[94]

- **New York.** In April 2014, the New York Public Service Commission opened the Reforming the Energy Vision (REV) proceeding to consider how to align electric utility practices and the state's regulatory framework with technological advances in information management and power generation and distribution.[95] In a white paper attached to the order,[96] the New York Department of Public Service (NYDPS) staff proposed to transform New York's electric industry to "make energy efficiency and other distributed resources a primary tool in the planning and operation of an interconnected modernized power grid." The NYDPS proceeding consists of two tracks. The first track involves a collaborative process to examine the role of distribution utilities in enabling market-based deployment of distributed energy resources to promote load management and greater system efficiency, including peak load reductions. The second track, undertaken in parallel with the first stage, but on a later timeline, will examine changes in current regulatory, tariff, and market designs and incentive structures to better align utility interests with achieving the Commission's policy objectives.[97]

  In the April 2014 white paper, NYDPS staff identified several issues related to demand response under this proposed framework: (1) how to align various wholesale and retail market rules for demand response to fully capture the value of distribution-level markets; (2) how to address the potential for multiple payments for demand response resources called simultaneously by the Distributed System Platform Provider (DSPP) and the NYISO; and (3) whether participation in New York ISO's demand response programs could fall as the DSPP takes on the role of demand response aggregator.[98] In August 2014, NYDPS staff released its straw proposal on Track One issues, finding, among other things, that the New York Public Service Commission should adopt the basic elements of the REV vision and proceed with implementation as proposed.[99] A policy decision on

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[94] Order Adopting Framework for Time Varying Rates, D.P.U. 14-04-C, (MA DPU Nov. 5, 2014), *available at* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=14-04%2fOrder_1404C.pdf.

[95] Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding, Case 14-M-0101, (NY PSC Apr. 25, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b9CF883CB-E8F1-4887-B218-99DC329DB311%7d.

[96] Reforming the Energy Vision, Case 14-M-0101, (NYDPS Apr. 25, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b9CF883CB-E8F1-4887-B218-99DC329DB311%7d.

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

[98] Reforming the Energy Vision, Case 14-M-0101, (NYDPS Apr. 25, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b9CF883CB-E8F1-4887-B218-99DC329DB311%7d.

[99] Developing the REV Market in New York: DPS Staff Straw Proposal On Track One Issues, Case 14-M-0101, (NYDPS Aug. 22, 2014), *available at* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BCA26764A-09C8-46BF-9CF6-F5215F63EF62%7D. Note: the acronym for Distributed System Platform Provider was shortened to DSP in this straw proposal, and refers to both the platform function and the platform entity.

Track One is expected in early 2015. Proposals and decisions in Track Two will occur later in 2015, starting with a NYDPS staff straw proposal that is expected to be issued on January 30, 2015.

- **Pennsylvania.** In a February 20, 2014 order,[100] the Pennsylvania Public Utilities Commission (PAPUC) proposed a new methodology for setting peak reduction targets under Act 129, based on the Statewide Evaluator's conclusion that programs under the current method[101] are not cost-effective, even when including benefits from price suppression in the wholesale markets.[102] Specifically, the PAPUC proposes, in line with the Statewide Evaluator's recommendation, to replace the current 100 hour methodology with one that bases demand response hours on a comparison of day-ahead and peak load forecasts, calling an event if the day-ahead load forecast is above a certain percentage of the peak load forecast. The order also directs the Statewide Evaluator to conduct a demand response potential study for the state using both the current and proposed methods. Additionally, the PAPUC directed the Statewide Evaluator to exclude potential revenue from bidding demand response resources into PJM's capacity market when estimating program cost-effectiveness.

- **Rhode Island.** The Rhode Island Public Utilities Commission (RIPUC) approved National Grid's proposal to continue its Load Curtailment Pilot in the Tiverton/Compton Area, which tests whether demand response can manage local distribution capacity requirements during peak periods.[103] Demand response events under the pilot begin in 2014, and use the demand response capabilities of wifi thermostats, lighting ballasts, and smart plugs installed in previous years of the pilot, along with certain new technologies to be offered to customers. Participation in demand response events is voluntary; however, customers opting out forfeit their annual bill credit. National Grid estimates that the pilot will result in lifetime demand savings of more than 2 MW in the Tiverton/Compton area.[104]

- **Texas.** Development of retail demand response continues in Texas. CPS Energy in San Antonio, in partnership with Honeywell, will offer a new automated demand response (ADR) program to its commercial and industrial customers. Based on pilot program achievements, the full-fledged program is expected to be the largest ADR program

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[100] Peak Demand Cost Effectiveness Final Order, Docket Nos. M-2012-2289411 and M-2008-2069887, (PAPUC Feb. 20, 2014), *available at* http://www.puc.pa.gov/pcdocs/1269801.doc.

[101] Currently, under Phase I of Pennsylvania's Energy Efficiency and Conservation (EE&C) program, the Pennsylvania Commission required each utility to reduce annual peak demand by 4.5 percent in its 100 highest hours of demand. *See* Energy Efficiency and Conservation Program Implementation Order, Docket No. M-20008-2069887, (PAPUC Jan. 16, 2009) *available at* http://www.puc.pa.gov/electric/pdf/Act129/EEC_Implementation_Order.pdf.

[102] GDS Associates, *Act 129 Demand Response Study: Final Report*, (Nov. 1, 2013), preparing report for PAPUC, *available at* http://www.puc.pa.gov/pcdocs/1256728.docx.

[103] In Re: the Narragansett Electric Company d/b/a National Grid's Energy Efficiency Program Plan for 2014 and 2014 System Reliability Procurement Report, Order No. 21298, Docket Nos. 4451 & 4453, (RIPUC Dec. 24, 2013), *available at* http://www.ripuc.org/eventsactions/docket/4451-4453-NGrid-Ord21298_12-24-13.pdf.

[104] National Grid, *2014 Reliability System Procurement Report*, Submitted to the RIPUC, Docket No. 4453, (Nov. 1, 2013), *available at* http://www.ripuc.org/eventsactions/docket/4453-Ngrid-SRP2014_11-1-13.pdf.

offered by a municipal utility, if the target of 6 MW of potential reduction is realized.[105] In the residential market, Austin Energy's "Rush Hour Rewards" program takes advantage of the capabilities of the Nest smart thermostat to provide demand response services to homeowners. Enrollees receive a one-time $85 rebate for allowing the utility to manage air conditioning usage on event days through the Nest thermostat.[106] The process is automatic: the thermostat receives upcoming demand response event information from the utility and adjusts temperature settings accordingly: precooling the home before an event and turning the temperature up afterwards. Customers receive event notification through multiple channels, and can override temperature settings.[107]

- **Virginia.** Dominion Virginia Power is conducting an ongoing dynamic pricing pilot, approved by the State Corporation Commission in 2011 and expanded and modified in 2013.[108] The pilot allows a limited number of residential and small and medium commercial customers to voluntarily enroll in dynamic rate plans that divide the year into high-, medium-, and low-priced days, and have a different number of pricing periods (i.e., on-peak/off-peak or on-peak/shoulder/off-peak) each day, depending on the time of year. Residential customers pay a demand charge each month. Commercial customers pay a demand charge that may include a ratchet above 30 MW, and may also be subject to critical peak pricing charges. An evaluation of the pilot estimates that, on high-priced summer days, the average residential program participant reduced electricity demand (kW) by 6.5% during on-peak hours, 3.9% during shoulder hours, and 1.3% during off-peak hours, compared to a control group. In addition, residential participants shifted a small amount of demand to off-peak periods. The evaluation found no statistically significant reductions in usage by commercial customers. Dominion plans to continue the pilot through January 2016.[109]

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[105] Press Release, Honeywell, Honeywell and CPS Energy Expand Efforts to Help Make the Electrical Grid Smarter, More Reliable, (Mar. 26, 2014), *available at* https://www.honeywellsmartgrid.com/en-US/NewsEvents/PressR/Pages/Honeywell-and-CPS-Energy-Expand-Efforts-to-Help-Make-the-Electrical-Grid-Smarter,-More-Reliable.aspx.

[106] MIT Technology Review, The Lowly Thermostat, Now Minter of Megawatts, (May 20, 2014), *available at* http://www.technologyreview.com/news/527366/the-lowly-thermostat-now-minter-of-megawatts/.

[107] Nest, What is Rush Hour Rewards, (June 2, 2014), *available at* http://support.nest.com/article/What-is-Rush-Hour-Rewards.

[108] In re: Virginia Electric and Power Company's proposed pilot program on dynamic rates, Case No. PUE-2010-00135 (VA State Corp. Comm'n Aug. 26, 2013), *available at* http://docket.scc.state.va.us/CyberDocs/Libraries/Default_Library/Common/frameviewdsp.asp?doc=132115&lib=CASEWEBP_LIB&mimetype=application%2Fpdf&rendition=native.

[109] *Annual Report to the State Corporation Commission Of Virginia Electric and Power Company On its Dynamic Pricing Pilot*, Case No. PUE-2010-00135 (VA State Corp. Comm'n July 31, 2014), *available at* http://docket.scc.state.va.us/CyberDocs/Libraries/Default_Library/Common/frameviewdsp.asp?doc=138188&lib=CASEWEBP_LIB&mimetype=application%2Fpdf&rendition=native. *See also* Appendix 5, *Dominion Virginia Power's Dynamic Pricing Pilot: Evaluation Report – Final*, prepared by DNV GL, Inc., July 7, 2014.

Industry demand response actions

Leadership in Energy and Environmental Design

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. With the incorporation of the demand response credit in late 2013,[110] the focus is now on identifying and overcoming barriers to the development of the automated demand response market. The USGBC and the Environmental Defense Fund founded the Demand Response Partnership Program to conduct research on the implementation of automated demand response; create a forum for utilities, service providers, and managers of LEED registered buildings to discuss their experiences with the credit program; and to publish case studies. In addition to incorporating the demand response credit, LEED is moving towards a more performance-based, less prescriptive approach to building management.[111] Along these lines, the USGBC launched its LEED Dynamic Plaque in late 2013, a performance benchmarking system that aggregates and displays near real-time information about the building's energy and water use, waste production, and occupant experience.[112]

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[110] U.S. Green Building Council, About LEED v4, *available at* http://www.usgbc.org/articles/about-leed-v4.

[111] Heather Langford, USGBC and Ross Malme, Skipping Stone, Peak Load Management Alliance Demand Response Dialogue, DR Trailblazing in Commercial Buildings (May 1, 2014), *available at* http://www.peakload.org/?page=DRDialogueGBC.

[112] ECOBuilding Pulse, Green for Life, (Jan. 28, 2014), *available at* http://www.ecobuildingpulse.com/leed/a-leed-dynamic-plaque-for-every-building-new-and-old_o.aspx. *See also* LEED, LEED Dynamic Plaque, *available at* http://www.leedon.io/.

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[113] 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.

- **Lack of Uniform Standards for Communicating Demand Response Pricing, Signals and Usage Information.** The acceptance and deployment of common information models and protocols such as OpenADR, Smart Energy Profile 2.0, and Green Button gained momentum in the past year. For example, following the release of the more advanced OpenADR 2.0b standard in June 2013, acceptance and deployment of OpenADR accelerated, with the certification of devices such as Ecobee smart thermostats.[114] In addition, the OpenADR 2.0b profile was successfully tested to provide ancillary services and regulation signaling in PJM.[115] More importantly, the International Electrotechnical Commission (IEC) approved the OpenADR 2.0b Profile Specification as a Publicly Available Specification (PAS) as a basis for a new IEC standard to be developed, validating the global importance of the OpenADR smart grid specification.[116] As mentioned earlier, Federal agencies were directed to adopt Green Button in a Presidential Memorandum in December 2014.

- **Lack of Support for Enabling Technologies.** The deployment of enabling technologies also gained momentum with the entry of many new companies and technology platforms into the home automation and "smart homes" market.[117] For example, Google announced developer programs in June 2014 that will allow other devices within a home to share data with Nest thermostats. Apps and devices that develop interfaces to Nest devices will be able "to access what Nest detects through its sensors, including vague readings on temperature and settings that show if a person is

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

[114] The Ecobee smart thermostat is an example of a wifi-enabled smart thermostat intended for the residential market.

[115] Press Release, IPKeys, PJM, Walmart, Berkeley Lab and Schneider Electric Demonstrate Energy Management Advances with OpenADR 2.0b Market Pilots, (May 13, 2014) *available at* http://www.bloomberg.com/bb/newsarchive/a6zIY35HGwZE.html.

[116] Barbara Vergetis Lundin, OpenADR smart grid specification approved, *FierceSmartGrid*, (Feb. 25, 2014) *available at* http://www.fiercesmartgrid.com/story/openadr-smart-grid-specification-approved/2014-02-25#ixzz31tYOJCho.

[117] Stacey Higginbotham, Gigaom, *There are many paths to a smart home. And that's the problem*, (July 27, 2014), *available at* http://gigaom.com/2014/07/27/there-are-many-paths-to-a-smart-home-and-thats-the-problem/.

away from their home for long periods."[118] Nevertheless, the proliferation of incompatible technologies may prove challenging in the near term.

- **Opportunities for Customer Education and Engagement.** Utilities currently have a very narrow window within which to communicate with and engage their customers. A recent Accenture survey estimates that utility customers interact with their utilities for only nine minutes per year.[119] Lack of engagement may partially explain why residential customers have been slow to adopt time-based rates, where they have the option to participate. Navigant Research estimates that, overall, less than one percent of U.S. households are on dynamic rates.[120] In response, some utilities have started to offer demand response programs that incorporate sophisticated strategies for engaging customers. For example, BGE's behavioral demand response offering (supported by Opower) combines a peak time rebate with communication strategies specifically aimed to engage customers, such as personalized energy savings tips, communication through multiple channels, immediate feedback on individual results, and comparisons with similar households. BGE plans to roll out the program to its entire customer base by 2015.[121]

  New York is emphasizing utility customer engagement as part of its REV initiative. In its April white paper, the NYDPS identifies several best practices for customer education and outreach, including mixing traditional outreach methods (e.g., bill inserts) with social media and community-based marketing approaches, and accommodating customer diversity in the design of demand side management programs (i.e., through customer segmentation). NYDPS also notes the need for market participants to identify and account for the cultural and behavioral factors that affect energy use, and to design incentives and technologies that increase customers' knowledge and ability to manage their energy bills.[122] Research addressing many of these areas is ongoing. For example, proceedings from the annual Behavior, Energy and Climate Change (BECC) conference are one source for recent research on the application of customer outreach and

[118] Parmy Olsen, Google's Nest Moves To Become Master Of The Smart Home, By Talking To Other Devices, *Forbes*, June 24, 2014, *available at* http://www.forbes.com/sites/parmyolson/2014/06/24/google-nest-smart-home-internet-of-things/.

[119] Accenture, *The New Energy Consumer Handbook, (*June 6, 2013), *available at* http://nstore.accenture.com/acn_com/PDF/Accenture-New-Energy-Consumer-Handbook-2013.pdf

[120] Navigant Research, *Less Than 1 Percent of Residential Electricity Customers Will Adopt Dynamic Pricing Rates by 2020 Unless Utilities Act Aggressively*, (October 9, 2013), *available at* http://www.navigantresearch.com/newsroom/less-than-1-percent-of-residential-electricity-customers-will-adopt-dynamic-pricing-rates-by-2020-unless-utilities-act-aggressively.

[121] Press Release, Opower, *How Baltimore Gas and Electric is Solving the Dynamic Pricing Puzzle*, (Jan. 13, 2014), *available at* http://blog.opower.com/2014/01/how-baltimore-gas-and-electric-is-solving-the-dynamic-pricing-puzzle/.

[122] NYDPS, *Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal*, Case 14-M-0101, (Apr. 24, 2014), *available at* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming The Energy Vision (REV) REPORT 4.25. 14.pdf.

segmentation methods to the design of demand response and energy efficiency programs.[123]

- **Implementing Time-based Pricing.** As noted above, less than one percent of U.S. households are on dynamic rates. The availability of technology, however, is no longer the major factor limiting the deployment of time-based rates – by 2015, 50 percent of U.S. households are projected to have a smart meter.[124] Some regulators, consumer advocates and others may still have open concerns about the effects of dynamic pricing on certain customer classes.

  Results from the Department of Energy's Smart Grid Investment Grant Consumer Behavior Studies may help to address these concerns. Preliminary data shows that, on average, more customers are enrolled in default time-based rate programs that require the customer to opt out (84%) than are enrolled in programs that require that the customer to opt-in (11%).[125] SMUD, a participant in DOE's grant program, found in its interim program evaluation that customers in the default (opt-out) treatment group remained enrolled at a high rate (93-99%), while a relatively large share of customers in the opt-in treatment group enrolled (16.4-18.8%).[126] Based on the results of this study, SMUD plans to make time-varying rates the default for most customers by 2018.[127]

  With few exceptions, such as Massachusetts, other states are not proposing to adopt default time-based pricing plans, despite reported growing demand for such plans.[128] As noted above, in November 2014, the Massachusetts DPU issued a *Policy Framework for Time Varying Rates* as part of their larger grid modernization investigation. In their policy framework, the Department responded to the comments received on time-varying rates, and sets forth the Department's policy framework for time varying rates in Massachusetts. Core to the policy framework is that default electricity supply provided

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[123] Behavior, Energy & Climate Change Conference, BECC Presentations 2013, *available at* http://beccconference.org/2013-pre-conference-workshops/.

[124] IEE, *Powering the People: Next Generation Utility – Opening Animation* (video), (Mar. 6, 2014), *available at* http://www.edisonfoundation.net/iee/ourwork/Pages/Videos.aspx.

[125] DOE, *Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies*, July 2013, *available at* https://www.smartgrid.gov/sites/default/files/doc/files/DOE_CBS_report_final_draft-7-10-13.pdf.

[126] Sacramento Municipal Utility District and Freeman, Sullivan & Co., *SmartPricing Options Interim Evaluation: An interim evaluation of the pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study*, (Oct. 23, 2013), *available at* https://www.smartgrid.gov/sites/default/files/MASTER_SMUD CBS Interim Evaluation_Final_SUBMITTED TO TAG 20131023.pdf.

[127] Catherine Wolfram, Smart Meters But Dumb Pricing? Not in Sacramento, (Nov. 18, 2013), *available at* http://energyathaas.wordpress.com/2013/11/18/smart-meters-but-dumb-pricing-not-in-sacramento/. On October 7, 2013, California enrolled Chapter 611 allowing utilities in the state to offer default time-based pricing plans beginning in 2018. California State Legislature, AB 327, Adopted October 7,013, *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

[128] Ahmad Faruqui, Address to the 3rd Guangdong, Hong Kong, Macau Power Industry Summit, The Global *Tao* of the Smart Grid, (Nov. 7, 2013), *available at* http://www.brattle.com/system/publications/pdfs/000/004/954/original/The_Global_Tao_of_the_Smart_Grid.pdf?1383853471.

by the distribution companies should include time varying rates for all rate classes following the deployment of advanced metering functionality.[129]

[129] Anticipated Policy Framework for Time Varying Rates, D.P.U. 14-04-B, (MA DPU June 12, 2014) *available at* http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf.

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