2018 Assessment of

Demand Response and Advanced Metering

Staff Report
Federal Energy Regulatory Commission
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FERC Staff Report

ASSESSMENT OF DEMAND RESPONSE AND ADVANCED METERING

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

November 2018

Chapter 1: Introduction

This report is the Federal Energy Regulatory Commission staff's (Commission staff's) thirteenth annual report on demand response and advanced metering required by section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005). The information presented in the report is based on publicly-available data and discussions with industry experts. Highlights of the report include the following:

- Advanced meters[1] are the most prevalent type of metering deployed throughout the country, accounting for nearly half of all meters installed and operational in the United States. According to the Energy Information Administration (EIA),[2] 70.8 million advanced meters were operational nationwide in 2016 out of a total of 151.3 million meters, indicating a 46.8 percent penetration rate;
- Over the past year, electric utilities in Florida, Mississippi, Rhode Island, Virginia, and elsewhere received approval for, or proposed, large-scale deployment of advanced meters, in some cases as part of grid modernization efforts. In Massachusetts, Kentucky, and elsewhere, state regulators and utilities are taking more targeted or cautious approaches to advanced meter deployment, while other states such as Texas are seeking to get more benefits out of their existing advanced meters by leveraging those investments through, for example, data sharing mechanisms;
- Regulators in several states, including Maryland, Minnesota, Ohio, and Pennsylvania, have approved, or are considering, time-based rate pilots, some in combination with proposed electric vehicle charging infrastructure investments. In other states, including California and Pennsylvania, regulators are considering next steps for demand response and time-based rate programs; and
- Demand resource participation in the wholesale markets increased by approximately three percent from 2016 to 2017, to a total of 27,541 MW. The contribution of demand

[1] As defined by the U.S. Energy Information Administration (EIA), Advanced Metering Infrastructure (AMI) Meters (also referred to throughout this report as "advanced meters") are "[m]eters 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." Other types of meters currently in use—such as standard electromechanical, standard solid state, and Automated Metering Reading (AMR) meters—are not considered advanced meters for the purposes of this report. *See* EIA, Form EIA-861: Annual Electric Power Industry Report Instructions, at 18, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

[2] EIA, Form EIA-861 Advanced_Meters_2016 data file (released November 2017).

resources to meeting peak demand increased to 5.6 percent in 2017 from 5.3 percent in 2016.

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

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems (Chapter 2);
(B) existing demand response programs and time-based rate programs (Chapter 5);
(C) the annual resource contribution of demand resources (Chapter 3);
(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes (Chapter 4);
(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party (Chapter 5); and
(F) regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs (Chapter 6).

Chapter 2: Saturation and penetration rate of advanced meters

This chapter reports on penetration rates for advanced meters, and developments related to grid modernization and advanced metering. As summarized in Table 2-1, Figure 2-1, and noted in previous staff reports, recent data indicate that advanced meters are now the dominant metering technology type, and the number of advanced meters in operation continues to increase in the United States. This trend is robust across several data sets.

Table 2-1: Estimates of Advanced Meter Penetration Rate

Source	Data As Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate (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	Dec 2011	37.3 [4]	144.5 [4]	25.8%
Institute for Electric Efficiency	May 2012	35.7 [5]	144.5 [4]	24.7%
2012 Form EIA-861	Dec 2012	43.2 [6]	145.3 [6]	29.7%
Institute for Electric Innovation	July 2013	45.8 [7]	145.3 [6]	31.5%
2013 Form EIA-861	Dec 2013	51.9 [8]	138.1 [8]	37.6%
Institute for Electric Innovation	July 2014	50.1 [9]	138.1 [8]	36.3%
2014 Form EIA-861	Dec 2014	58.5 [10]	144.3 [10]	40.6%
2015 Form EIA-861	Dec 2015	64.7 [11]	150.8 [11]	42.9%
Institute for Electric Innovation	Dec 2015	65.6 [12]	150.8 [11]	43.5%
2016 Form EIA-861	Dec 2016	70.8 [13]	151.3 [13]	46.8%
Institute for Electric Innovation	Dec 2016	72.0 [14]	151.3 [13]	47.6%

Sources:
[1] FERC, *Assessment of Demand Response and Advanced Metering staff report* (2008). [2] FERC, *Assessment of Demand Response and Advanced Metering staff report* (2011). [3] FERC, *Assessment of Demand Response and Advanced Metering staff report* (2012). [4] 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. [5] The Edison Foundation Institute for Electric Efficiency, *Utility-Scale Smart Meter Deployments, Plans & Proposals* (2012). [6] EIA, Form EIA-861 and Form EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (October 29, 2013). [7] The Edison Foundation Institute for Electric Innovation, *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits* (2013). [8] EIA, Form EIA-861: Advanced_Meters_2013 data file (re-released June 8, 2015). The number of total meters—including AMI, AMR and standard electromechanical meters—was reported for the first time in 2013. Therefore, we no longer use the number of customers as a proxy. *See* source note 4 above and *Form EIA-861Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf. [9] The Edison Foundation Institute for Electric Innovation, *Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid* (2014). [10] EIA, Form EIA-861: Advanced_Meters_2014 data file (re-released January 13, 2016). [11] EIA, Form EIA-861: Advanced_Meters_2015 data file (re-released November 1, 2016). [12] The Edison Foundation Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (2016). [13] EIA, Form EIA-861: Advanced_Meters_2016 data file (re-released November 6, 2017). [14] The Edison Foundation Institute for Electric Innovation, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2017).

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 2016 EIA data,[3] 70.8 million advanced meters were operational out of a total of 151.3 million meters nationwide, representing a 46.8 percent penetration rate. This number of advanced meters represents an increase of approximately six million advanced meters, or an almost four percent increase, from 2015 to 2016.[4] Data from the Edison Foundation shows similar figures for the number and penetration rate of advanced meters.

Figure 2-1 shows the growth of advanced meters over time. Over the period 2007-2016, the number of advanced meters in operation has increased more than ten-fold.

Figure 2-1: Advanced Meter Growth (2007 – 2016)

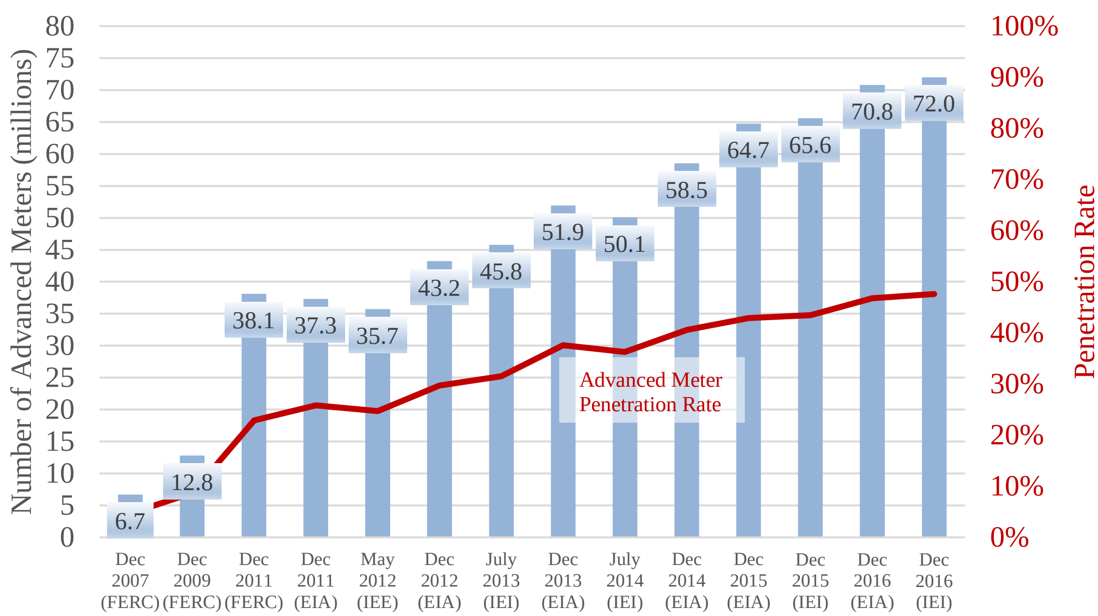

Table 2-2 below provides estimated advanced meter penetration rates by NERC region, Alaska (AK) and Hawaii (HI),[5] and retail customer class. Advanced meters represent more than half of all meters in four regions: approximately 86 percent of meters in Texas RE, 60 percent in WECC, and approximately 58 percent in SPP RE[6] and in FRCC. The largest absolute growth in advanced meters from 2015 to 2016 occurred in RF and SERC, where 2.3 million and 1.5 million additional advanced meters, respectively, went into operation. The highest percentage growth in advanced meters took place in AK, with an increase of about 17 percent, and SPP RE,

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[3] EIA, Form EIA-861: Advanced_Meters_2016 data file (re-released November 6, 2017).

[4] *Id.* EIA data also reveals that advanced meters are the predominant metering technology installed and operational throughout the United States.

[5] For the time period examined, NERC comprised eight regional entities in the lower 48 states: the Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (Texas RE), and Western Electricity Coordinating Council (WECC). The states of Alaska (AK) and Hawaii (HI) are not subject to NERC oversight. *See* Appendix and NERC, *NERC Regions Map*, http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/2017_NERC_Regions_May2017.jpg.

[6] On May 4, 2018, FERC approved a joint petition to transfer NERC registered entities within the SPP RE footprint to MRO and SERC. *NERC, MRO and SERC*, 163 FERC ¶ 61,094 (2018).

with an increase of about nine percent. Advanced meter penetration increased in all regions from 2015 to 2016.

Table 2-2 indicates that, nationwide, advanced meters are slightly more common among residential and commercial sectors compared to the industrial sector. In 2016, advanced meters accounted for approximately 47 percent of all residential meters, 45 percent of all commercial meters, and 41 percent of all industrial meters. Within regions, there is noticeable variation in advanced meter penetration by customer class. For example, in AK, RF, SERC, SPP RE, Texas RE, and WECC, the residential sector has a higher rate of advanced meter penetration than the commercial or industrial sector. In contrast, in FRCC, HI, and MRO, advanced meter penetration is highest in the industrial sector.

Table 2-2: Advanced Meter Penetration Rate by Customer Class and NERC Region

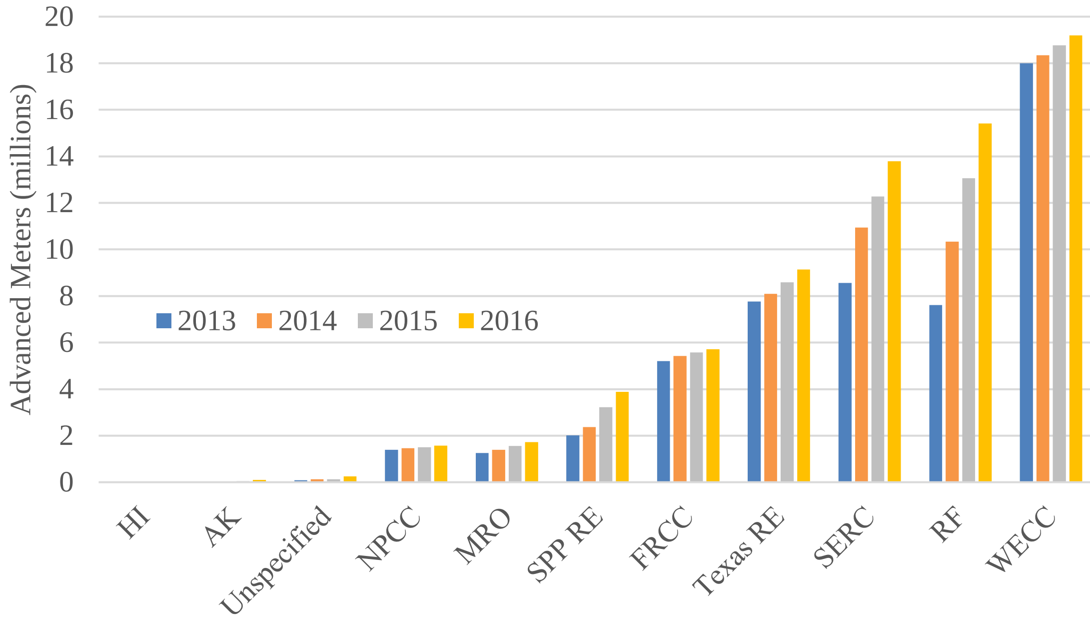
Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
AK	30.8%	17.5%	10.4%	28.7%
FRCC	56.9%	62.2%	72.2%	57.6%
HI	6.2%	7.2%	16.1%	6.3%
MRO	22.4%	19.0%	26.9%	22.0%
NPCC	10.1%	9.1%	11.9%	10.0%
RF	44.4%	37.7%	29.8%	43.6%
SERC	43.8%	41.6%	37.8%	43.5%
SPP RE	58.6%	53.9%	51.1%	57.8%
Texas RE	86.1%	85.8%	58.0%	85.9%
WECC	60.6%	59.9%	44.9%	60.4%
Unspecified	34.7%	32.3%	27.8%	34.4%
All Regions	**47.1%**	**44.8%**	**40.5%**	**46.8%**

Sources: EIA, 2016 Form EIA-861 Advanced_Meters_2016 data file.

Note: The transportation sector data collected by EIA contain a relatively small number of meters, and are not reported separately here. In addition, although some entities may operate in more than one NERC Region, EIA data have only one NERC region designation per entity. The "unspecified" category represents respondents to the EIA-861 short form, which were not required to report a NERC region, as well as other respondents that did not specify a single NERC region. Commission staff has not independently verified the accuracy of EIA data.

Figure 2-2 shows increases in the number of advanced meters in all NERC regions from 2013-2016. All regions experienced year-on-year growth in the number of advanced meters from 2013 to 2016, while RF experienced the most growth since 2013. WECC continues to have the largest number of advanced meters installed overall. Large increases in the total number of advanced meters were seen in SERC and RF from 2015 to 2016, a continuation of the trend seen since 2013 in these regions, while AK and SPP experienced the greatest annual percentage increases from 2015 to 2016.

Figure 2-2: Number of Advanced Meters by NERC Region (2013 – 2016)



Developments and issues in advanced metering

State legislative and regulatory activity related to advanced metering

Presently, state regulators and utilities appear to be past the early adoption stage of advanced meter deployment, as the penetration rate of advanced meters nears 50 percent. Over the past year, electric utilities in a number of states received approval for, or proposed, large-scale deployment of advanced meters, in some cases as part of grid modernization efforts. Elsewhere, state regulators and utilities are taking more targeted or cautious approaches to advanced meter deployment, while other states are seeking to get more benefits out of their existing advanced meters by leveraging those investments through, for example, data sharing mechanisms. Below we provide updates on these activities.

- **Arizona**. On September 12, 2017, the Arizona Public Service Company (APS) received approval from the Arizona Corporation Commission (ACC) to charge residential customers a fee to voluntarily opt out of receiving an advanced meter and to instead receive a non-AMI meter. Through a settlement agreement with stakeholders and interested parties, the original APS proposal was reduced from a one-time fee of $70 plus $15 a month, to a one-time fee of $50 plus $5 a month.[7]

- **Florida**. On November 20, 2017, the Florida Public Service Commission (Florida PSC) approved a settlement agreement between Duke Energy Florida (DEF) and organizations

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[7] *In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return*, Docket No. E-01345A-16-0036, Decision No. 76374 (ACC Sept. 19, 2017) at 6, http://docket.images.azcc.gov/0000182797.pdf.

representing DEF's major customer groups increasing base rates for the utility.[8] As part of the settlement agreement, DEF will invest $1.2 billion in grid modernization,[9] which includes full deployment of advanced meters and services like usage alerts, outage notifications, and customized billing options, and will launch a five-year electric vehicle charging station pilot program for at least 530 vehicles with no more than $8 million of operating and maintenance expenses.[10]

- **Hawaii**. On June 21, 2018, Hawaiian Electric Company (HECO Companies) filed an application requesting approval to implement Phase 1 of its Grid Modernization Strategy,[11] which the Hawaii Public Utilities Commission (Hawaii PUC) previously approved on February 7, 2018.[12] Phase 1 of the strategy consists of advanced meter deployment on an "opt-in"[13] basis, as well as deployment of related software and telecommunications systems, and is proposed to run from 2019 to 2023 at a cost of approximately $86.3 million.[14]

- **Illinois**. On August 16, 2018, the Seventh Circuit Court of Appeals ruled that data collected by the Naperville City-owned electric utility through advanced meter readings at 15-minute intervals are a reasonable search under the state's constitution and the Fourth Amendment of the U.S. Constitution. Naperville Smart Meter Awareness, a group of concerned citizens, argued that the utility's collection of advanced meter data could reveal intimate personal details of members' actions while in their homes, and that collection of this data violates the state and Federal constitution.[15] While the court found that the data collection constitutes a warrantless search, it balanced the intrusion on individuals' privacy interests with the legitimate government interests behind installing advanced meters, such as faster outage restoration, reduction of utility labor costs,

[8] *In Re: Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement, Including Certain Rate Adjustments, by Duke Energy Florida, LLC*, Order No. PSC-2017-0451-AS-EU (Florida PSC Nov. 20, 2017), http://www.floridapsc.com/library/filings/2017/09951-2017/09951-2017.pdf.

[9] Duke Energy Florida, *2017 Settlement Agreement at a Glance*, https://www.duke-energy.com/annual-report/_/media/pdfs/for-your-home/def-settlement-overview.pdf?la=en.

[10] *In Re: Application for Limited Proceeding to Approve 2017 Second Revised and Restated Settlement Agreement, Including Certain Rate Adjustments, by Duke Energy Florida, LLC*, Order No. PSC-2017-0451-AS-EU (Florida PSC Nov. 20, 2017) at 33-34, http://www.floridapsc.com/library/filings/2017/09951-2017/09951-2017.pdf.

[11] *In the Matter of the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred Costs through the Major Project Interim Recovery, and Related Requests*, Docket no. 2018-0141 (Hawaii PUC June 21, 2018), https://www.hawaiianelectric.com/Documents/about_us/our_commitment/20180621_grid_mod_strategy_application_filing.pdf.

[12] *Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy*, Docket No. 2017-0226, Order No. 35268 (Hawaii PUC Feb. 7, 2018), https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18B08B13014I00232.

[13] HECO Companies contrasts the proposed "opt-in" approach, through which customers can choose whether to receive an advanced meter, to previous applications in which it sought to deploy advanced meters to all customers. *In the Matter of the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, to Defer Certain Computer Software Development Costs, to Recover the Capital and Deferred Costs through the Major Project Interim Recovery, and Related Requests*, Docket no. 2018-0141 (Hawaii PUC June 21, 2018) at 34, https://www.hawaiianelectric.com/Documents/about_us/our_commitment/20180621_grid_mod_strategy_application_filing.pdf.

[14] *Id*. at 4.

[15] *Naperville Smart Meter Awareness v. City of Naperville*, 900 F.3d 521, 524 (7th Cir. 2018).

increased grid stability, and the priority to modernize the electric grid.[16] Although the court found that the City of Naperville's interests outweighed the individuals' in this case, it cautioned that were the city to collect data at shorter intervals, or the data were more easily accessible to law enforcement or other city officials, its conclusion could change.[17]

- **Kentucky**. On August 30, 2018, the Kentucky Public Service Commission (Kentucky PSC) rejected Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company's (KU) jointly-filed application to install 1.3 million advanced meters across their service territories.[18] The Kentucky PSC found that LG&E and KU failed to present sufficient evidence to support a demonstration that there is a need for advanced meters, particularly considering the substantial remaining service lives of their existing meters.[19] Accordingly, the Kentucky PSC found that the utilities failed to demonstrate that a full deployment of advanced meters would not lead to wasteful duplication of investments in their existing meters.[20] In spite of that finding, the Kentucky PSC stated that it sees benefits in advanced metering, encouraged LG&E and KU to expand their current pilot program for advanced meters from 10,000 total customers to 20,000 total customers, and also encouraged the utilities to consider real-time pricing options.[21]

- **Massachusetts**. On May 10, 2018, the Massachusetts Department of Public Utilities (Massachusetts DPU) rejected Eversource and National Grid's grid modernization plans, and a similar proposal by Unitil, stating that the companies' proposals to install advanced meters "revealed weaknesses in the business case for advanced metering functionality."[22] Specifically, the Massachusetts DPU found that recent technological advances may permit interval data collection without the need to replace existing meters, although those meters would still require additional devices to enable two-way communications.[23] As stated by the DPU, any decision to prematurely retire the existing meters would come at a significant cost.[24] Additionally, the DPU found that the primary benefit of advanced meters lies in reduced peak usage as customers respond to price signals. However, without wide customer adoption of time-based rates, the benefits of advanced meters remain uncertain.[25] The order noted that the Massachusetts DPU intends to open an investigation into how to remove barriers to time-based rates for customers, and provide

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16 *Id*. at 528–529.
17 *Id*. at 529.
18 *In the Matter of Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems*, Case No. 2018-00005 (Kentucky PSC Aug. 30, 2018), https://psc.ky.gov/pscscf/2018%20Cases/2018-00005//20180830_PSC_ORDER.pdf.
19 *Id*. at 7.
20 *Id*. at 7.
21 *Id*. at 14-15.
22 *Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid for Approval by the Department of Public Utilities of its Grid Modernization Plan, et. al.*, Mass DPU Order Nos. 15-120, 15-121, 15-122 (Massachusetts DPU May 10, 2018) at 1-2, https://eeaonline.eea.state.ma.us/EEA/FileService/FileService.Api/file/FileRoom/9163509.
23 *Id*. at 133.
24 *Id*. at 134.
25 *Id*. at 1-2.

certainty that the benefits justify the costs for implementation of advanced meters.[26] Specifically, the Massachusetts DPU will consider (1) whether it is cost-effective to undertake targeted deployment of advanced meters to customers most likely to be engaged and participate in time-based rate programs, and (2) technology options that could enable cost-effective deployment of advanced meter functionality without necessitating replacement of existing meters.[27]

- **Minnesota**. On May 31, 2018, the Minnesota Public Utilities Commission (Minnesota PUC) approved a pilot program proposed by Xcel Energy that includes deployment of advanced meters, including the provision of increased energy usage information, education, and support to encourage shifting energy usage to off-peak hours to customers with advanced meters.[28] The program also includes a pilot for time-of-use rates,[29] discussed further in Chapter 5 of this report. The program is scheduled to begin in early 2020, and will be deployed to about 10,000 customers.[30]

- **Mississippi**. On April 10, 2018, the Mississippi Public Service Commission (Mississippi PSC) approved a Mississippi Power Company proposal to deploy advanced meters in their service territory.[31] The plan will deploy approximately 193,000 advanced meters across 23 counties throughout its service territory,[32] at a cost of $39 million over the next two years.[33]

- **New York**. The New York State Energy Research and Development Authority (NYSERDA) and the state's Clean Energy Fund, will provide $15 million in funding for "High Performing Grid" projects like advanced monitoring and controls, advanced sensors, devices, and systems, and advanced system modeling.[34] In order to achieve the

[26] *Id*. at 2-3.
[27] *Id*. at 135-136.
[28] *Staff Briefing Papers*, Docket Nos. E-002/M-17-775, E-002/M-17-776 (Minnesota PUC May 31, 2018) at 28, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={009E9263-0000-C016-8875-BD1FFA2ED2C5}&documentTitle=20185-143296-01.
[29] *Order Approving Pilot Program, Setting Reporting Requirements, and Denying Certification Request*, Docket Nos. E-002/M-17-775, E-002/M-17-776 (Minnesota PUC Aug. 7, 2018), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90C81565-0000-C411-A2FE-612297DE478D}&documentTitle=20188-145592-01.
[30] *Staff Briefing Papers*, Docket Nos. E-002/M-17-775, E-002/M-17-776 (Minnesota PUC May 31, 2018) at 29, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={009E9263-0000-C016-8875-BD1FFA2ED2C5}&documentTitle=20185-143296-01.
[31] *In Re: Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing the Acquisition, Construction, and Operation of Advanced Metering Infrastructure Equipment, Technology, and Related Facilities*, Docket No. 2009-UA-398 (Mississippi PSC Apr. 10, 2018), http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=402804.
[32] Itron, *Itron Signs Agreement with Mississippi Power to Deploy and Manage Nearly 200,000 Smart Meters across the Magnolia State* (May 2018), https://www.itron.com/cn/newsroom/press-releases/2018/05/14/itron-signs-agreement-with-mississippi.
[33] *In Re: Petition of Mississippi Power Company for a Certificate of Public Convenience and Necessity Authorizing the Acquisition, Construction, and Operation of Advanced Metering Infrastructure Equipment, Technology, and Related Facilities*, Docket No. 2009-UA-398 (Mississippi PSC Apr. 10, 2018), http://www.psc.state.ms.us/InSiteConnect/InSiteView.aspx?model=INSITE_CONNECT&queue=CTS_ARCHIVEQ&docid=402804.
[34] New York State, *Governor Cuomo Announces $15 Million to Support Modernization of New York's Electric Grid* (Apr. 2018), https://www.governor.ny.gov/news/governor-cuomo-announces-15-million-support-modernization-new-yorks-electric-grid.

goals of the Reforming the Energy Vision (REV) initiative, the program seeks to incentivize investments that result in, among other things, increased use of distributed energy resources, and that make the grid more efficient and reliable.[35]

- **North Carolina**. On June 22, 2018, the North Carolina Utilities Commission (NCUC) rejected[36] the Duke Energy Carolinas (DEC) Power/Forward grid modernization initiative,[37] and instructed the utility instead to use existing dockets such as the Integrated Resource Planning and Smart Grid Technology Plan to recover costs. However, the NCUC order did approve cost recovery for DEC's full deployment of advanced meters throughout its service territory.[38]

- **Rhode Island**. On November 27, 2017, the Narragansett Electric Company (National Grid) filed an application with the Rhode Island Public Utilities Commission (Rhode Island PUC) to increase its revenue requirements in order to, among other things, complete a full deployment of advanced meters across its service territory over a three year period after approval, and introduce customers to time-of-use rates two years after that,[39] as part of the Power Sector Transformation Initiative reported in the 2017 version of this report.[40] On June 6, 2018, National Grid submitted a settlement agreement between the utility and interested parties to the Rhode Island PUC.[41] The Rhode Island PUC approved the settlement agreement on August 24, 2018.[42]

- **Texas**. On July 12, 2018, the Public Utility Commission of Texas (PUCT) approved the plan for implementation of the Smart Meter Texas web portal, an interoperable, web-based information system that, among other things, (1) stores retail customers' data in 15-minute intervals recorded by advanced meters, and (2) provides authorized stakeholders with secure access to that data in order to sell services such as energy efficiency and demand response.[43] Smart Meter Texas is jointly maintained by four transmission and

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[35] NYSERDA, *Electric Power Transmission and Distribution High Performing Grid*, https://portal.nyserda.ny.gov/CORE_Solicitation_Detail_Page?SolicitationId=a0rt000000DbjBFAAZ.

[36] *In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1146 (NCUC June 22, 2018) at 19, http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

[37] Duke Energy, *Duke Energy Embarks on a 10-year Initiative to Strengthen North Carolina's Energy Grid* (Apr. 2017), https://news.duke-energy.com/releases/duke-energy-embarks-on-a-10-year-initiative-to-strengthen-north-carolina-s-energy-grid?_ga=1.192735209.238488252.1492423359.

[38] *In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1146 (NCUC June 22, 2018) at 19, http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

[39] *Power Sector Transformation Panel Book 1 of 3*, Docket No. 4770 (Rhode Island PUC Nov. 27, 2017) at 74-75, http://www.ripuc.org/eventsactions/docket/4770-NGrid-PSC-Book1of3.pdf.

[40] FERC, *Assessment of Demand Response and Advanced Metering* at 14 (2017), https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf.

[41] *Proposed Power Sector Transformation Vision and Implementation Plan Settlement Agreement*, Docket Nos. 4770, 4780 (Rhode Island PUC June 6, 2018), http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-Transmittal-SettlementAgreement(6-6-18).pdf.

[42] State of Rhode Island, *Public Utilities Commission Approves Power Sector Transformation Settlement in National Grid Rate Case* (Aug. 2018), http://www.ripuc.ri.gov/consumerinfo/Settlement_Release.pdf.

[43] *Commission Staff's Petition to Determine Requirements for Smart Meter Texas*, Docket No. 47472 (PUCT July 12, 2018), http://interchange.puc.texas.gov/Documents/47472_138_986459.PDF.

distribution utilities: AEP Texas, CenterPoint Energy Houston Electric, Oncor Electric Delivery Company, and Texas-New Mexico Power Company.[44]

- **Virginia**. On July 1, 2018, Virginia's Grid Transformation and Security Act went into effect.[45] Among other things, the law ends a freeze on utility rates and creates a model that allows utilities to invest in projects that are deemed "in the public interest," such as grid modernization programs.[46]

  On July 24, 2018, Dominion Energy filed Phase I of its Grid Transformation Plan with the State Corporation Commission for the Commonwealth of Virginia (Virginia SCC), which includes full deployment of advanced meters across its service territory by the end of 2023. The plan also includes among other things, proposals for a customer information platform (CIP) to leverage information provided by advanced meters. For example, the CIP will provide customers with access to detailed energy usage information, enabling them to select rate structures—including time-based rate options—to meet their needs.[47]

[44] *Commission Staff's Petition to Determine Requirements for Smart Meter Texas*, Docket No. 47472 (PUCT July 12, 2018) at 3, http://interchange.puc.texas.gov/Documents/47472_138_986459.PDF.
[45] State of Virginia, SB 966, HB 1558, 2018 Session, approved on March 9, 2018, https://lis.virginia.gov/cgi-bin/legp604.exe?181+ful+CHAP0296.
[46] Code of Virginia, § 56-585.1(A)(6), https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/.
[47] *Petition of Virginia Electric and Power Company, for Approval of a Plan for Electric Distribution Grid Transformation Projects Pursuant to § 56.585.1(A)(6) of the Code of Virginia*, Case No. PUR-2018-00100 (Virginia SCC July 24, 2018), https://www.dominionenergy.com/library/domcom/media/about-us/electric-projects/grid-transformation/gtsa-072418.pdf?la=en.

Chapter 3: Annual resource contribution of demand resources

Using the latest publicly available data, this chapter summarizes the annual resource contribution from retail and wholesale demand response programs on a national and regional basis.[48]

Retail demand response programs

Table 3-1 presents data collected by EIA on 2015 and 2016 potential peak demand savings from retail demand response programs within each of the eight NERC regional entities, as well as Alaska (AK) and Hawaii (HI).[49] 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."[50] Nationwide, total potential peak demand savings from retail demand response programs increased by almost 3,050 megawatts (MW), or approximately nine percent, between 2015 and 2016, to 35,924 MW.[51]

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by NERC Region (2015 & 2016)

Region	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2015	2016	MW	%
AK	27.0	27.0	0.0	0.0%
FRCC	3,246.5	3,259.4	12.9	0.4%
HI	35.2	33.5	-1.7	-4.8%
MRO	4,508.9	5,231.3	722.4	16.0%
NPCC	787.4	1,120.2	332.8	42.3%
RF	5,372.2	5,505.1	132.9	2.5%
SERC	9,259.1	8,265.6	-993.5	-10.7%
SPP RE	1,922.7	5,004.4	3,081.7	160.3%
Texas RE	696.4	773.3	76.9	11.0%
WECC	7,019.2	6,625.3	-393.9	-5.6%
Unspecified	0.0	79.0	79.0	--
Total	**32,874.6**	**35,924.1**	**3,049.5**	**9.3%**

Sources: EIA, EIA-861 Demand_Response_2015, Demand_Response_2016, Utility_Data_2015, and Utility_Data_2016 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.

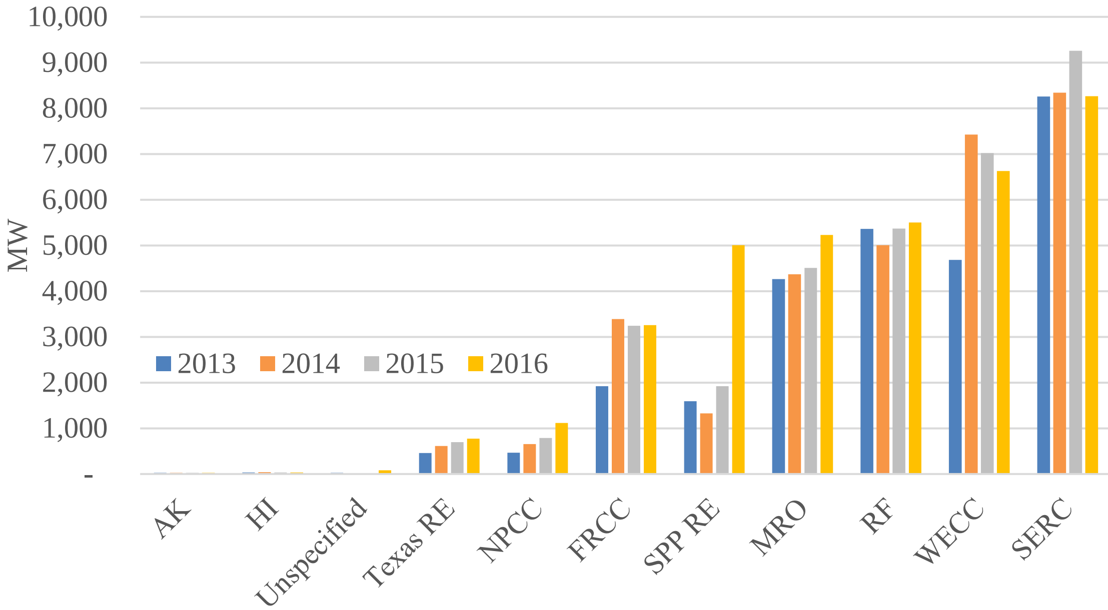
[48] The latest publicly available retail and wholesale data sets are used to determine the annual resource contributions from demand response programs; these include EIA retail data for 2015 and 2016, as well as RTO/ISO wholesale data for 2016 and 2017.

[49] This section categorizes potential peak demand savings from retail demand response programs by NERC region because such programs exist in regions both with and without organized wholesale markets.

[50] *See* EIA, Form EIA-861 Instructions, Schedule 6, Part B.

[51] The Smart Electric Power Alliance (SEPA) also conducts an annual survey to estimate capacity enrolled in retail demand response programs. Based on responses from 155 utilities representing 62.4% of total U.S. customer accounts, SEPA reports that there was 18.3 GW of demand response capacity enrolled in retail programs in 2017. *See* SEPA, 2018 Utility Demand Response Market Snapshot, at 12-13, https://sepapower.org/resource/2018-demand-response-market-snapshot/.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by NERC Region (2013 – 2016)



Regionally, however, there were large differences in the change in potential peak demand savings from 2015 to 2016. Table 3-1 and Figure 3-1 above show that potential peak demand savings increased in SPP RE by more than 3,000 MW from 2015 to 2016, attributable primarily to a 2,800 MW increase in peak demand savings reported by Oklahoma Gas & Electric. Peak demand savings in MRO increased by over 700 MW, with greater reported savings by MidAmerican Energy and Northern States Power Company-Minnesota (Xcel Energy). In contrast, net retail demand response potential fell sharply in SERC in 2016 due primarily to lower reported savings in Tennessee Valley Authority's industrial demand response program. Figure 3-1 also generally shows a trend of increasing retail peak demand response savings in most regions over the period 2013-2016.

Table 3-2 shows that the amount of potential peak demand savings from retail demand response differs by customer class in 2016. Industrial customer demand response represented 14,339 MW, or 40 percent, of total potential peak demand savings. Residential customer demand response accounted for approximately 10,518 MW, or 29 percent, and programs in the commercial sector accounted for almost 11,053 MW, or 31 percent, of total potential peak demand savings. The relative contribution by customer class varies by region. For example, residential demand response programs account for the largest portion of potential peak demand savings in WECC (47 percent) and MRO (approximately 40 percent). In contrast, commercial programs account for the majority of potential peak demand savings in AK, HI, SPP RE, and Texas RE. In FRCC, residential and commercial programs represent approximately the same proportion of potential peak savings, at 47 and 48 percent, respectively. Finally, industrial programs account for the majority in NPCC (60 percent), RF (55 percent), and SERC (71 percent).

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Region and Customer Class (2016)

Region	Customer Class				
	Residential	Commercial	Industrial	Transportation	All Classes
AK	5.0	13.0	9.0	0.0	27.0
FRCC	1,548.2	1,573.2	138.0	0.0	3,259.4
HI	14.8	18.7	0.0	0.0	33.5
MRO	2,083.6	1,434.6	1,713.1	0.0	5,231.3
NPCC	77.9	359.2	669.1	14.0	1,120.2
RF	1,644.8	828.2	3,032.1	0.0	5,505.1
SERC	1,652.6	755.8	5,857.2	0.0	8,265.6
SPP RE	149.3	3,751.3	1,103.8	0.0	5,004.4
Texas RE	213.5	406.5	153.3	0.0	773.3
WECC	3,116.6	1,867.2	1,641.5	0.0	6,625.3
Unspecified	12.0	45.0	22.0	0.0	79.0
All Regions	**10,518.3**	**11,052.7**	**14,339.1**	**14.0**	**35,924.1**

Sources: EIA, EIA-861 Demand_Response_2016 and Utility_Data_2016 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.

Wholesale demand response programs

Table 3-3 below presents demand resource participation in wholesale demand response programs operated by RTOs/ISOs in 2016 and 2017.[52] Given changes in the structure of demand response programs in some RTOs/ISOs over the past several years, as well as changes in the way that demand resource participation is reported in some regions, Commission staff has updated the methodology used in this section of the report.[53] Demand response participation figures for 2016 have been updated from those reported previously to provide an accurate comparison to 2017 figures.

Demand resource participation in the wholesale markets increased by approximately three percent from 2016 to 2017, to a total of 27,541 MW, as shown in Table 3-3.[54] The reported

[52] The RTOs/ISOs include California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

[53] Specifically, the figures reflect the registration of demand response resources (but not energy efficiency resources) in wholesale demand response programs. This applies in particular to ISO-NE, where energy efficiency resources make up a large portion of demand resources participating in the market. Additionally, figures for CAISO reflect demand resource participation in wholesale demand response products rather than in retail programs, as reported previously. In NYISO, figures include demand resources participating in the ancillary services market. Finally, because the data source previously used for ERCOT is no longer available, Commission staff has estimated demand resource participation based on ERCOT's 2016 and 2017 Annual Reports of Demand Response.

[54] Commission staff estimates are based on demand resource enrollment in reliability, energy, and ancillary services products administered by each RTO/ISO. In contrast, SEPA estimates a total of 19,314 MW of demand resources participating in only RTO/ISO reliability programs in 2017; these figures are based on capacity market obligations or reliability program enrollment

increase in wholesale demand resource participation is mainly attributable to an increase in demand resource participation in MISO and ERCOT, which was offset by small decreases in participation in other regions. Due to a decrease in peak demand levels in 2017, the contribution of demand resources to meeting peak demand also rose slightly from 5.3 percent in 2016 to 5.6 percent in 2017.

Table 3-3: Demand Resource Participation in RTO/ISO Demand Response Programs

	2016		2017		Year-on-Year Change	
RTO/ISO	Demand Resources (MW)	Percent of Peak Demand[8]	Demand Resources (MW)	Percent of Peak Demand[8]	MW	Percent
CAISO	1,480 [1]	3.2%	1,293 [9]	2.6%	-187	-12.6%
ERCOT	2,536 [2]	3.6%	3,009 [10]	4.3%	473	18.6%
ISO-NE	703 [3]	2.7%	684 [11]	2.9%	-19	-2.7%
MISO	10,721 [4]	8.9%	11,682 [12]	9.7%	961	9.0%
NYISO	1,373 [5]	4.3%	1,353 [13]	4.6%	-20	-1.4%
PJM	9,836 [6]	6.5%	9,520 [14]	6.5%	-316	-3.2%
SPP	0 [7]	0.0%	0 [7]	0.0%	0	0.0%
Total	**26,649**	**5.3%**	**27,541**	**5.6%**	**892**	**3.4%**

Sources:
[1] CAISO, *2016 Annual Report on Market Issues and Performance*, Table 1.3, at 33 (May 2017).
[2] Estimated based on ERCOT, *2016 Annual Report of Demand Response in the ERCOT Region*, at 2-6 (Mar. 2017).
[3] ISO-NE, *Demand Response Enrollment Statistics*, presented at Demand Resources Working Group Meeting (Jan. 9, 2017) (data as of Jan. 1, 2017), at 2. Figure represents enrolled MWs.
[4] *2016 State of the Market Report for the MISO Electricity Market* (June 2016), Table 8, at 72.
[5] *2016 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 12, 2017), Attachment I, Table 1, at 7.
[6] *PJM 2016 Demand Response Operations Markets Activity Report* (May 2017), at 3-4. Figure represents "unique MW."
[7] No load-reduction demand response activity has occurred in the Integrated Marketplace since it was established on March 1, 2014. *See* SPP Compliance Filing, Docket No. ER12-1179-024, at 4 (May 24, 2016); and SPP Response to Request for Additional Information, Docket No. ER12-1179-025, at 1-2, 4 (Mar. 5, 2018).
[8] Sources for peak demand data include: California ISO *2016* and *2017 Annual Reports on Market Issues and Performance*; *ERCOT 2016 & 2017 Demand and Energy Reports*; *ISO-NE Net Energy and Peak Load Report* (May 2017 & May 2018); *2016* and *2017 State of the Market Reports for the MISO Electricity Markets*; *NYISO Power Trends Reports 2017* and *2018*; *2016* and *2017 PJM State of the Markets Reports, Vol. 2*; *SPP 2017 State of the Market Report*.
[9] CAISO, *2017 Annual Report on Market Issues and Performance*, at 36-37 (June 2018).
[10] Estimated based on ERCOT, 2017 *Annual Report of Demand Response in the ERCOT Region*, at 2-6 (Mar. 2018).
[11] ISO-NE, *Demand Resource Asset Enrolled MWs*, presented at Demand Resources Working Group Meeting (Dec. 18, 2017) (data as of Jan. 1, 2018), at 2. Figure represents enrolled MW.
[12] *2017 State of the Market Report for the MISO Electricity Market* (June 2018), Table 11, at 78.
[13] *2017 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 12, 2018), Attachment I, at 6 (Table 1).
[14] *PJM 2017 Demand Response Operations Markets Activity Report* (April 2018), at 3-4. Figure represents "unique MW."

Note: Commission staff has not independently verified the accuracy of the sources listed. Values from source data are rounded for publication.

or market awards, depending on the region. *See* SEPA, *2018 Utility Demand Response Market Snapshot*, at 27, https://sepapower.org/resource/2018-demand-response-market-snapshot/.

In MISO, overall demand resource registrations increased by approximately nine percent, or 961 MW from 2016 to 2017. Of this increase in enrollment, 1,496 MW was from Demand Resource Load Modifying Resources (LMR),[55] which, according to the MISO market monitor, are becoming increasingly important in planning and emergency operations.[56] MISO also reported a 95 MW increase in Type I Demand Response Resources (DRR) for 2017. These increases were slightly offset by a decrease of 80 MW of Behind-the-Meter Generation LMRs, a decrease in enrollment of 75 MW of Type II DRRs,[57] and a 475 MW decrease in enrollment of non-LMR Emergency DR resources.

In ERCOT, demand resource participation grew by 473 MW, or about 19 percent, from 2016 to 2017. Most of this growth (456 MW) is due to increased participation in the Responsive Reserve Service (RRS).[58] In addition, the capacity of resources participating in the Fast Responding Regulation Service (FRRS)[59] increased by 20 MW, while participation in the Emergency Response Service (ERS)[60] remained relatively flat.

Demand resource participation in ISO-NE decreased from 703 MW to 684 MW, or about three percent, due to lower reported enrollment in the Real-Time Demand Response Program (RTDR). Decreases in RTDR enrollment were reported in five of ISO-NE's eight load zones, while RTDR enrollment increased in two zones. RTDR enrollment decreased in the New Hampshire (6 MW), Vermont (3 MW), Connecticut (13 MW), Western and Central Massachusetts (9 MW), and Northeast Massachusetts (8 MW) zones while increases were reported in the Rhode Island (4 MW) and Southeast Massachusetts (14 MW) zones. Real-Time Emergency Generation Resource enrollment, which has gradually declined for several years, was the same in 2017 as in 2016 at 1.5 MW.

In CAISO, participation fell by 187 MW in 2017 from the year before. Overall, 1,023 MW of demand resources were enrolled in the Reliability Demand Response program in 2017, a slight decrease from the 2016 total of 1,320 MW. In contrast, enrollment in the Proxy Demand Response program—through which resources can bid economically in the energy market—increased from 160 MW in 2016 to 270 MW in 2017.[61]

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[55] The vast majority of demand response capability in MISO consists of interruptible loads (Load Modifying Resources) developed under regulated utility programs that clear in MISO's annual capacity auction. *See* Potomac Economics, *2017 State of the Market Report for the MISO Electricity Market* (June 2018) at 79.

[56] *Id.*

[57] In 2016, only one resource was participating in the DRR – Type II product; by 2017 this resource was no longer participating in the market. *See* Potomac Economics, *2017 State of the Market Report for the MISO Electricity Market* (June 2018) at 79.

[58] Load resources with an under-frequency relay may participate in the RRS to provide frequency response. Commission staff estimated participation in the RRS program based on the average offers for December 2016 and 2017; resources must be registered and qualified to offer into the market. While ERCOT reports that as much as 4,715 MW of resources were capable of participating in RRS as of the end of 2017—a growth of 890 MW over 2016—not all of these resources were actively participating in the market. *See* ERCOT, *2017 Annual Report of Demand Response in the ERCOT Region* (Mar. 2018) at 2-4.

[59] ERCOT reports that several markets participants began offering FRRS in 2017 using energy storage resources. Average awards for FRRS increased by 20 MW in the last six months of 2017 to reach the hourly cap of 35 MW. *See id*. at 4.

[60] The ERS provides 10- and 30-minute load reduction services. Commission staff estimated ERS capacity for 2016 and 2017 by averaging the capacity procured for the six time periods in the last contract term of each program year (i.e., October to January), and summing these averages for each of the four ERS products (i.e., 10- and 30-minute types of weather-sensitive and non-weather-sensitive ERS). *See id*. at 5-6.

[61] In addition, in 2017, there were 1,759 MW of demand response capacity enrolled in programs administered by the three investor-owned utilities. Participation in utility-sponsored price-responsive programs has been gradually declining over the last

Demand resource participation also decreased slightly in NYISO and PJM, by approximately one percent and three percent, respectively. In NYISO, a 27 MW increase in Special Case Resource enrollment and a 10 MW increase in enrollment in the Demand-Side Ancillary Service Program were offset by a decrease in enrollment of 59 MW in the Emergency Demand Response Program.

PJM reports an overall decrease in demand resources enrollments of 316 MW from 2016 to 2017. Specifically, there was a 221 MW drop in enrollment in PJM's reliability programs overall, with a large portion of resources enrolled in the Limited Demand Resource (Limited DR)[62] product moving to the Extended Summer[63] and Annual Demand Resource (Annual DR)[64] products. There was also a 328 MW decrease in demand resources participating in the economic demand response program.[65] The overall decrease in demand resource registrations in PJM was likely due to a decrease in the quantity of demand resources offering into the 2017/2018 Base Residual Auction compared to the year before,[66] and the continued phasing out of legacy demand response products as PJM shifts to an annual capacity performance product.

SPP reports that no demand resources have participated in its Integrated Marketplace since the market was established in 2014.[67]

2018 demand response deployments

High temperatures during the summer of 2018 led grid operators and utilities in several regions to issue notices for emergency demand response, critical peak pricing, and voluntary conservation.

In response to high temperatures across the Western United States, high fire risk, and tight gas supply in Southern California in late July, CAISO issued a state-wide Flex Alert[68] calling for

several years as participation in wholesale programs has grown. *See* CAISO, *2017 Annual Report on Market Issues and Performance* (June 2018) at 36, 39.

[62] Limited DR (effective through the 2017/2018 delivery year) is available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. PJM, *Manual 18: PJM Capacity Market*, Revision 40 (Feb. 22, 2018), at 71, https://www.pjm.com/-/media/documents/manuals/m18.ashx.

[63] Extended Summer DR (effective through the 2017/2018 delivery year) is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. *Id.*

[64] Annual DR (effective through 2017/2018 delivery year) is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. *Id.*

[65] Some resources participate in both PJM's reliability and economic programs.

[66] PJM, *2017/2018 Base Residual Auction Results*, at 10, https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx.

[67] Submission of Tariff Revisions to Implement Order No. 745 in the SPP Integrated Marketplace, Docket No. ER12-1179-024, at 4 (filed May 24, 2016); and SPP Response to Request for Additional Information, Docket No. ER12-1179-025, at 1-2, 4 (filed Mar. 5, 2018).

[68] Flex Alerts are voluntary calls for consumers to conserve electricity when there is a predicted shortage of energy supply. *See* CAISO, *What Is a Flex Alert*, http://www.flexalert.org/what-is-flex-alert.

voluntary electricity conservation during the evening on July 24 and 25.[69] These measures resulted in demand savings of 450 MW on July 24 and 540 MW on July 25, when CAISO posted a new peak demand record of 46,424 MW.[70] Southern California Edison (SCE) separately called on customers participating in its Summer Discount Plan to allow the utility control over their air conditioning units for several hours from July 23-25 and August 6-7,[71] in exchange for a payment. More than 200,000 residential and 9,000 commercial customers are reported to have participated in the July event.[72] In addition, all three investor-owned utilities in California called critical peak pricing days on several occasions this summer: SCE in July and August,[73] Pacific Gas & Electric (PG&E) in mid-June and throughout July,[74] and San Diego Gas & Electric (SDG&E) on August 6 and 7.[75]

On July 2, NYISO activated an estimated 495 MW of emergency demand response for several hours in Zone J (New York City),[76] due to an extended heat wave in the region and the unexpected outage of a 345 kV transmission line in the city.[77] An estimated 481 MW of emergency demand response was again activated in Zone J on August 28 and 29, when NYISO experienced its 2018 summer peak load.[78]

On July 19, demand in ERCOT reached an all-time peak of 73,259 MW, approximately 2,100 MW higher than the previous record set in 2016.[79] Despite record demand and an estimated reserve margin this summer of 11 percent[80]—lower than normal—ERCOT did not issue notices for conservation or emergency demand response on this day.[81]

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[69] CAISO, *Flex Alert Notices*, http://www.caiso.com/informed/Pages/Notifications/Flex-Alerts.aspx.

[70] Greentech Media, *Californians Slash Energy Use to Protect the Electric Grid* (July 31, 2018), https://www.greentechmedia.com/articles/read/californians-slash-energy-use-to-protect-the-electric-grid.

[71] SCE, *Event History*, https://www.sce.openadr.com/dr.website/scepr-event-history.jsf.

[72] Greentech Media, *Californians Slash Energy Use to Protect the Electric Grid* (July 31, 2018), https://www.greentechmedia.com/articles/read/californians-slash-energy-use-to-protect-the-electric-grid.

[73] SCE, *Event History*, https://www.sce.openadr.com/dr.website/scepr-event-history.jsf.

[74] PG&E, *Review Peak Day Pricing Event Day History*, https://www.pge.com/en_US/business/rate-plans/rate-plans/peak-day-pricing/event-day-history.page.

[75] SDG&E, *Demand Response Program Status*, https://www.sdge.com/demand-response-program-status.

[76] NYISO, *NYISO Summer 2018 Hot Weather Operations*, presented to Management Committee Sept. 26, 2018, at 10, http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2018-09-26/04%20Summer%202018%20NYISO%20Hot%20Weather%20Operating%20Cond.pdf. *See also NYISO, Historic EDRP and SCR Activation Information* (Aug. 30, 2018), http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Demand_Response/Demand_Response_Activations/EXT-DR-Events-and-Tests-History-With-CPs.pdf.

[77] RTO Insider, *NYISO Management Committee Briefs: July 25, 2018* (July 29, 2018), https://www.rtoinsider.com/nyiso-summer-peak-demand-96986/. *See also* NYISO, *Operations Performance Metrics Monthly Report: July 2018 Report*, at 3, https://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2018-08-29/03%20OperationsReport.pdf.

[78] NYISO, *NYISO Summer 2018 Hot Weather Operations*, presented to Management Committee Sept. 26, 2018, at 15, http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2018-09-26/04%20Summer%202018%20NYISO%20Hot%20Weather%20Operating%20Cond.pdf. *See also* NYISO, *Operations Performance Metrics Monthly Report: August 2018 Report*, at 2, http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2018-09-26/03%20Operations_Report.pdf.

[79] EIA, *Electricity Reliability Council of Texas Surpassed All-Time Peak Hourly Load In July* (July 31, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36775.

[80] ERCOT, *ERCOT Expects Record-Breaking Peak Demand This Summer* (Apr. 30, 2018), http://www.ercot.com/news/releases/show/155101.

[81] ERCOT, *Public Notices*, http://www.ercot.com/services/comm/mkt_notices/notices/2018/07.

Due to higher than expected temperatures and unplanned generator outages, ISO-NE experienced an operating reserve shortage on September 3, the Labor Day holiday. In response, ISO-NE implemented several existing operating procedures, including a request for market participants to voluntarily reduce electricity consumption at their facilities.[82]

In addition, MISO activated emergency demand response (LMRs) on the evening of January 17, 2018—for only the second time since 2007—in response to unusually cold conditions in MISO South.[83]

[82] ISO Newswire, *Labor Day was No Holiday for New England's Power Grid: Weather and Resource Outages Led to Capacity Shortage Conditions* (Sept. 7, 2018), http://isonewswire.com/updates/2018/9/7/labor-day-was-no-holiday-for-new-englands-power-grid-weather.html.
[83] Potomac Economics, 2017 State of the Market Report for the MISO Electricity Market (June 2018) at 6-10.

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

NERC's Demand Response Availability Data System

The North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO) of North America, develops and enforces mandatory reliability standards that provide for reliable operation of the bulk power system.[84] NERC uses transmission, generation, and demand response data systems to analyze past performance of the bulk power system and to identify performance trends.[85] Specifically, NERC's Demand Response Availability Data System (DADS), measures demand response performance, in part, to gauge the extent to which the resource reliably and consistently performs to ensure reliable planning and operations. In its latest *State of Reliability* report, NERC notes that demand response "can support reliability during forecast or actual reserve shortages, reliability events, or assisting with frequency control." [86] For example, NERC reports that deployment of demand response resources increased during extreme heat conditions on the East Coast and Northeast during 2013, the Polar Vortex of 2014, and the West Coast during summer of 2015.[87]

In the past year, the NERC DADS working group continued efforts to improve data collection, quality control, and reporting through outreach and development of training materials. Specifically, the working group has taken steps to ensure the implementation of a uniform approach to reporting and measuring performance, including developing a data quality control document at the end of 2017.[88] With respect to demand response, the objective of the data quality control document is to define the types of quality controls that are applied to the demand response data reporting process "to ensure that application data are complete, accurate, and timely to support analysis and compute metrics for evaluating the performance of the bulk electric system."[89] In addition, NERC expects to complete a training video for, and to provide software-based training to, NERC DADS users in 2018.[90]

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[84] 16 U.S.C. §§ 824o(a)(2), 824o(c) (2005).
[85] NERC, *State of Reliability 2018* (June 2018) at vi, xii, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_2018_SOR_06202018_Final.pdf. Specifically, these are NERC's Transmission Availability Data System (TADS), the Generation Availability Data System (GADS), and the Demand Availability Data System (DADS). DADS collects three categories of demand response data: Program Type, Registered Capacity, and Events.
[86] *Id.* at 6.
[87] *Id.* at 105. In addition, PJM's analysis of the 2014 Polar Vortex states that PJM called on demand response three times during the event, and that the "availability and response of voluntary demand response" exceeded PJM's expectations in real-time. Further, PJM's analysis notes that voluntary demand response, "although not required to respond during the winter [of 2013/2014], did respond and assisted in maintaining the reliability of the system." *See* PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 8, 2014) at 20-21, https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.
[88] Donna Pratt, *Data Quality Control Process*, presented to Generating Availability Data System Working Group, Sept. 19-20, 2017), https://www.nerc.com/comm/PC/Generating%20Availability%20Data%20System%20Working%20Gro1/Item%205%20%20GADSWG-Sept%202017-Data%20Quality%20Document.pdf.
[89] *Id.* at 3.
[90] NERC, DADS working group, January 11, 2018 meeting notes.

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

Based on EIA survey data and program definitions, this chapter provides information on retail demand response[91] and time-based rate programs[92] in 2015 and 2016, and summarizes recent actions taken at the federal, regional, and state levels, and by industry, related to demand response.

Enrollment in retail demand response and time-based rate programs

As shown in Table 5-1 below, in 2016 the number of retail customers enrolled in (incentive-based) demand response programs nationwide increased by eight percent to approximately 9.8 million customers, the highest number of customers enrolled in demand response programs since 2013.

On a regional basis, the largest percentage increase in customer enrollment in retail demand response programs occurred in the RF region, where enrollments increased by about 50 percent from 2015 to 2016 to 2.4 million total customers. According to EIA data, this increase was primarily due to higher reported enrollment in programs run by Potomac Electric Power Company, Delmarva Power, and DTE Electric Company. Other regions also reported an increase in the number of customers enrolled in demand response programs. The number of customers in WECC rose by about six percent, or approximately 176,000 customers, due primarily to increases in the number of commercial customers enrolled in San Diego Gas & Electric Company's territory. In addition, Texas RE reported an increase of 26,000 customers, or about a nine percent increase from 2015.

In contrast, enrollment fell by 16 percent, or almost 230,000 customers, in SERC due to reported decreases in enrollment in programs run by Duke Energy Progress and Virginia Electric & Power Company (Dominion). Enrollment in SPP RE fell by 11 percent, or approximately 21,000 customers, primarily due to lower reported enrollment in the residential program run by Kansas Gas & Electric Company. Enrollment also fell in FRCC, NPCC, and for entities that did not specify a NERC region. These entities reported a net decrease in enrollment of

[91] Demand response programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. Previously, EIA referred to these programs as "incentive-based" demand response programs. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part B, https://www.eia.gov/survey/form/eia_861/instructions.pdf; and FERC, *A National Assessment of Demand Response Potential* (2009), http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf.

[92] Time-based rate programs include real-time pricing, critical peak pricing, critical peak rebate, variable peak pricing, and time-of-use rates administered through a tariff. EIA now refers to these programs as "dynamic pricing" programs. *See* EIA, Form EIA-861 Instructions, Schedule 6-Part C, https://www.eia.gov/survey/form/eia_861/instructions.pdf.

approximately 4,000 customers due primarily to a decline in reported enrollment by TXU Energy Retail Company LP.

Table 5-1: Customer Enrollment in Retail Demand Response Programs, by Region (2015 & 2016)

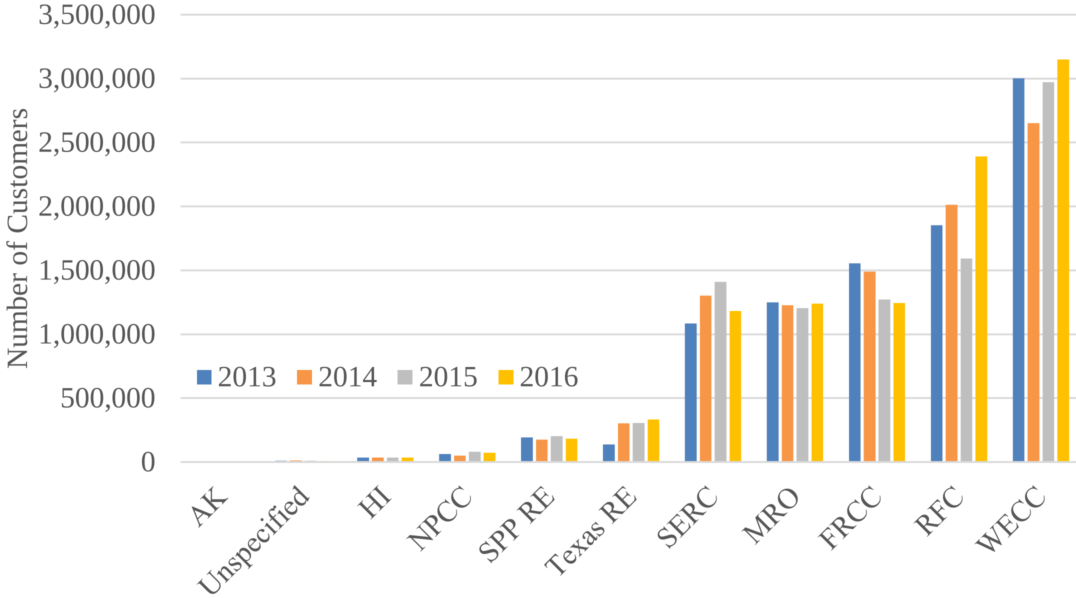
Region	Enrollment in Retail Demand Response Programs		Year-on-Year Change	
	2015	2016	Customers	Percent
AK	2,431	2,403	-28	-1.2%
FRCC	1,271,487	1,245,403	-26,084	-2.1%
HI	36,008	36,160	152	0.4%
MRO	1,205,568	1,239,580	34,012	2.8%
NPCC	80,884	72,969	-7,915	-9.8%
RF	1,591,730	2,390,143	798,413	50.2%
SERC	1,410,799	1,180,884	-229,915	-16.3%
SPP RE	204,020	182,576	-21,444	-10.5%
Texas RE	307,089	333,236	26,147	8.5%
WECC	2,972,779	3,148,899	176,120	5.9%
Unspecified	11,343	7,102	-4,241	-37.4%
Total	**9,094,138**	**9,839,355**	**745,217**	**8.2%**

Sources: EIA, EIA-861 Demand_Response_2015, Utility_Data_2015, Demand_Response_2016, and Utility_Data_2016 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 described above, despite decreases in some regions since a peak in 2013, 2014, or 2015, the number of customers enrolled in retail demand response programs nationwide has increased since 2013, as shown in Figure 5-1.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by NERC Region (2013 – 2016)



As Table 5-2 below indicates, there were almost eight million customers enrolled in retail time-based rate programs in the United States in 2016, an increase of approximately 361,000 customers, or 4.8 percent, from 2015. The bulk of this increase in absolute terms occurred in the RF and WECC regions, with approximately 154,000 and 124,000 new customer enrollments, respectively. EIA data indicate the increase in time-based rate program enrollments for the RF region is primarily due to an increase in enrollment in existing residential programs run by Baltimore Gas & Electric and Commonwealth Edison. The increase in enrollment in WECC is primarily due to significant enrollment increase in existing residential and commercial programs run by SDG&E and SCE. Texas RE reported the highest percentage increase from 2015, with the increase primarily attributable to over 2,300 new customers enrolled in commercial programs run by MP2 Energy LLC, a power marketer.

Table 5-2: Customer Enrollment in Retail Time-based Rate Programs, by Region (2015 & 2016)

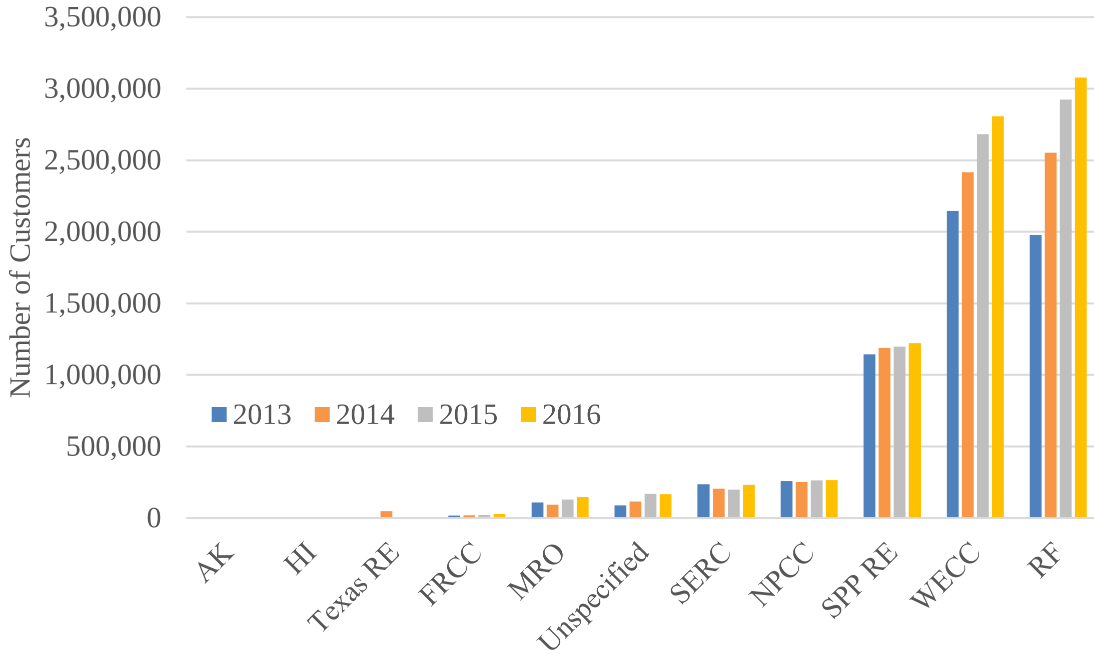
Region	Enrollment in Retail Time-based Rate Programs 2015	Enrollment in Retail Time-based Rate Programs 2016	Year-on-Year Change Customers	Year-on-Year Change Percent
AK	53	55	2	3.8%
FRCC	21,444	27,578	6,134	28.6%
HI	538	568	30	5.6%
MRO	129,558	146,396	16,838	13.0%
NPCC	262,030	265,619	3,589	1.4%
RF	2,923,239	3,077,442	154,203	5.3%
SERC	198,627	230,997	32,370	16.3%
SPP RE	1,198,489	1,222,479	23,990	2.0%
Texas RE	1,867	4,720	2,853	152.8%
WECC	2,683,400	2,807,596	124,196	4.6%
Unspecified	169,815	166,777	-3,038	-1.8%
Total	**7,589,060**	**7,950,227**	**361,167**	**4.8%**

Sources: EIA, EIA-861 Dynamic_Pricing_2015 and Dynamic_Pricing_2016 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.

Figure 5-2 below shows annual customer enrollment in retail time-based rate programs. SPP, WECC, and RF have reported annual increases in the number of customers from 2013 through 2016. SERC and NPCC reported higher enrollment in 2016 than in 2015. Similar to customer enrollment in demand response programs in Figure 5-1, the number of customers enrolled in time-based rate programs nationwide has increased in most regions since 2013.

Figure 5-2: Customers Enrolled in Retail Time-based Rate Programs by NERC Region (2013-2016)



FERC demand response orders and activities

Since the last staff report, the Commission issued several demand response-related orders.

AEE's Petition for Declaratory Order on Energy Efficiency (Docket No. EL17-75)

Based on a petition for declaratory order filed by Advanced Energy Economy (AEE) on the Commission's jurisdiction to regulate the participation of certain energy efficiency resources (EERs) in the wholesale electricity markets, the Commission issued on December 1, 2017 an order granting in part and denying in part AEE's petition.[93] In the order, the Commission found that it has exclusive jurisdiction to regulate the participation of EERs in organized wholesale electric markets; found that a relevant electric retail regulatory authority may not bar, restrict, or otherwise condition the participation of EERs in wholesale electricity markets unless the Commission expressly gives relevant electric retail regulatory authorities such authority; and held that Order No. 719 does not provide for a relevant electric retail regulatory authority to exercise an opt-out with respect to EERs. On April 17, 2018, on rehearing, among other things, the Commission affirmed its finding that it has exclusive jurisdiction over the participation of EERs in the organized wholesale electricity markets, and granted requested clarifications that the Commission did not assert the authority to preempt the terms and conditions established by relevant electric retail regulatory authorities for retail customers to receive retail service.[94]

[93] *Advanced Energy Economy*, 161 FERC ¶ 61,245 (2017).
[94] *Advanced Energy Economy*, 163 FERC ¶ 61,030 (2018).

PJM Seasonal Aggregation (ER17-367)

On February 23, 2018, the Commission approved a set of proposed modifications to PJM's tariff to improve the ability of certain resource types[95] to participate in PJM's capacity market.[96] The approved modifications include enhancements to PJM's aggregation rules to allow these types of resources to form aggregations across different deliverability areas and among different seasonal products. In addition, the approved modifications increase the ability of certain limited resources to obtain additional Capacity Interconnection Rights for the winter period to support aggregation, and improve the measurement and verification of demand resource performance during winter periods.

MISO Exemption from Withholding for Demand Resources (ER17-806)

On August 17, 2017, the Commission approved MISO's proposed tariff revisions related to market monitoring and mitigation in its annual Planning Resource Auction.[97] In the order, the Commission found that it is reasonable for MISO to exempt Demand Resources, Energy Efficiency Resources, and External Resources from market monitoring and mitigation in the context of the annual Planning Resource Auction. The Commission stated that these resource types can already decide on an annual basis whether to register to participate in the market, and that encouraging the participation of these resources is beneficial to the annual Planning Resource Auction.

Electric Storage Resource Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (Order No. 841)

The Commission issued Order No. 841 on February 15, 2018.[98] In Order No. 841, the Commission acted on the proposals included in the Commission's Notice of Proposed Rulemaking (NOPR) issued in November 2016 with respect to the participation of electric storage resources in the capacity, energy, and ancillary service markets operated by RTOs and ISOs, while not taking final action on the proposed distributed energy resource aggregation reforms in the NOPR. To remove barriers to the participation of electric storage resources in the RTO and ISO markets, Order No. 841 requires each RTO and ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO and ISO markets. The Commission made two clarifications regarding the relationship between demand response programs and the requirement to establish a participation model for electric storage resources. First, where an RTO/ISO already has a separate participation model that electric storage resources may use (such as for pumped-hydro resources or demand response), the Commission did not require the RTO/ISO to consolidate that participation model with the participation model for electric storage resources required by the order. Second, the Commission clarified that electric storage resources are not precluded from continuing to participate in demand response programs or under other participation models through which they are eligible to participate.[99] Order No. 841 required each RTO/ISO to file any tariff changes needed to

[95] Such as Capacity Storage Resources, Intermittent Resources, Demand Resources, Energy Efficiency Resources, and Environmentally-Limited Resources.
[96] *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,159 (2018).
[97] Midcontinent Independent System Operator, Inc., 160 FERC ¶ 61,005 (2017).
[98] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018).
[99] *Id.* PP 55-56.

implement the requirements of the Final Rule within 270 days of its publication in the Federal Register.

While the November 2016 NOPR also proposed reforms related to distributed energy resource aggregations, Order No. 841 found that more information was needed with respect to those proposals. Consequently, the Commission chose not to take final action on those proposed reforms. Instead, the Commission convened a technical conference on distributed energy resource aggregation on April 10-11, 2018 in Docket Nos. RM18-9-000 and AD18-10-000 to collect additional information.

Other federal demand response activities

U.S. Department of Defense

The Department of Defense's (DoD) Defense Logistics Agency Energy (DLA Energy) provides the DoD and other government agencies with comprehensive energy solutions,[100] including administering incentive-based demand response programs. In fiscal year 2017, DLA Energy operated 39 demand response installations in eight states and the District of Columbia—all of which are within organized wholesale markets—and had 115 MW of demand response enrolled in its programs.[101] These figures are lower than fiscal year 2016, when DLA Energy reported having 68 installations and approximately 200 MW of demand response enrolled.[102]

In addition, the DoD is procuring behind-the-meter battery storage systems to provide peak shaving, among other services, at several installations. These include a 4.25 MW / 8.5 MWh lithium-ion battery energy storage system under construction at Fort Carson, Colorado—the largest stand-alone commercially contracted battery at an army base—and a 1 MW / 1 MWh system at a U.S. Army depot in Tooele, Utah.[103]

U.S. General Services Administration

The General Services Administration (GSA) provides centralized procurement services for the federal government, including helping federal agencies to build, acquire, operate, and maintain office space, and preserving historic federal properties.[104] GSA continues to enable the participation of facilities it manages in various demand response and energy efficiency programs,

[100] U.S. DoD, Defense Logistics Agency Energy, *Fiscal Year 2017 Fact Book*, at 3, http://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2017FactBookLowRes2.pdf?ver=2018-03-29-073051-897.
[101] *Id*. at 54.
[102] U.S. DoD, Defense Logistics Agency Energy, *Fiscal Year 2017 Fact Book*, at 54, http://www.dla.mil/Portals/104/Documents/Energy/Publications/E_Fiscal2016FactBookWebResolution_170706.pdf.
[103] Utility Dive, *US Military Pushes Clean Energy with Largest On-Base Battery* (Aug. 22, 2018), https://www.utilitydive.com/news/us-military-pushes-clean-energy-with-largest-on-base-battery/530671/. *See also* PR Newswire, *AECOM and Lockheed Martin to enhance energy resilience at Fort Carson with DoD's largest peak-shaving battery* (Aug. 21, 2018), https://www.prnewswire.com/news-releases/aecom-and-lockheed-martin-to-enhance-energy-resilience-at-fort-carson-with-dods-largest-peak-shaving-battery-300700033.html; and Go Electric, *Go Electric Inc. Awarded $1.7M Contract to Deliver Battery Energy Storage System to Tooele Army Depot* (Jul. 25, 2017), http://nebula.wsimg.com/c3bd5230b162c5ba82a8e3523e05212d?AccessKeyId=D97AF8D908DF87B827C4&disposition=0&alloworigin=1.
[104] GSA, *Background and History*, https://www.gsa.gov/about-us/background-and-history.

earning revenues that offset facility costs. For example, GSA buildings in the agency's Northeast and Caribbean Region earned approximately $430,000 in 2017-2018 through participation in demand response programs in New York and New Jersey. The number of GSA buildings participating in demand response programs in the region, and associated revenues, have grown over time, totaling $2.3 million since participation began in fiscal year 2011.[105]

Developments and issues in demand response

State legislative and regulatory activities related to demand response and time-based rates

This section highlights developments in retail demand response and time-based rate activities. In the past year, regulators in several states have approved, or are considering, time-based rate pilots, some in combination with proposed electric vehicle charging infrastructure investments, due to an interest in incenting off-peak charging of electric vehicles. In other states regulators are considering next steps for demand response and time-based rate programs.

- **Arizona**. As of July 5, 2018, the Arizona Corporation Commission (ACC) is considering a set of proposed rules for the Arizona Energy Modernization Plan.[106] Specifically, the proposals include an 80 percent renewable energy target by 2050, a 3 GW energy storage target by 2030, and an electric vehicle infrastructure target to support one million electric vehicles by 2050.[107]

  In mid-2018, the Salt River Project (SRP) rolled out a "bring your own thermostat" pilot program called Flex Rewards. Under the program, customers may buy their own utility-compatible thermostat that allows SRP to reduce peak demand at a maximum of 15 conservation events per summer, in exchange for a credit on program participants' electric bills.[108]

- **California**. After the last round of its Demand Response Auction Mechanism (DRAM) pilot program[109] in June 2018, the California Public Utilities Commission's (CPUC) Energy Division staff presented preliminary results of their independent analysis of the program to the CPUC.[110] The CPUC found that the results were too complex to be

[105] GSA, *GSA Region 2 Marks Earth Day with Millions in Taxpayer Savings* (May 1, 2018), https://www.gsa.gov/about-us/regions/welcome-to-the-northeast-caribbean-region-2/region-2-newsroom/press-releases/gsa-region-2-marks-earth-day-with-millions-in-taxpayer-savings.
[106] *Draft Set of Formal Rules for the Arizona Energy Modernization Plan (CREST)*, Docket No. E-00000Q-16-0289 (ACC July 5, 2018), http://images.edocket.azcc.gov/docketpdf/0000189786.pdf.
[107] *Draft Set of Formal Rules for the Arizona Energy Modernization Plan (CREST)*, Docket No. E-00000Q-16-0289 (ACC July 5, 2018) at 7, http://images.edocket.azcc.gov/docketpdf/0000189786.pdf.
[108] SRP, *SRP Flex Rewards: FAQ*, https://enrollmythermostat.com/faqs/srpflexrewards/.
[109] The CPUC required the three investor-owned utilities in the state to establish Demand Response Auction Mechanism pilots to test the viability of using a competitive procurement mechanism for aggregated demand response sources to provide local, system, and flexible capacity. *See Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC June 9, 2016).
[110] The CPUC had previously required Energy Division staff to conduct an assessment of the program to determine whether the DRAM should be the primary means of sourcing demand response in the state. *See Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements*, Docket No. R.13-09-011 (CPUC Sept. 29, 2016).

addressed quickly and informally, so it extended the deadline to decide whether the DRAM will become a permanent program to July 17, 2019.[111]

On June 26, 2018, Southern California Edison filed a proposal with the CPUC to expand its electric vehicle charging infrastructure pilot program, aiming for 48,000 charging stations costing $760 million over four years.[112]

On July 31, 2018, Honda introduced a SmartCharge program that shifts electric vehicle charging based on real-time grid conditions. The program enables electric vehicle customers to participate in wholesale demand response events, and to receive payments in exchange for allowing their vehicle charging to be optimized based on electricity prices, grid needs, and their charging preferences. The program is only available for customers with a Honda Fit electric vehicle, but Honda plans to study the results of the program with the possibility of applying it to its other electric vehicles in the future.[113]

- **Hawaii**. On April 18, 2018, the Hawaii Public Utilities Commission (Hawaii PUC) opened a proceeding to investigate performance-based regulation for Hawaii utilities, in response to ongoing changes in the state's electric power industry.[114] The Hawaii PUC states that performance-based ratemaking can be used to provide rewards for specific outcomes and objectives, such as integrating technological advances like advanced metering and demand response capabilities.[115]

- **Maryland**. On February 6, 2018, the Maryland Public Service Commission (Maryland PSC) opened a proceeding to consider the implementation of an electric vehicle infrastructure portfolio.[116] The portfolio—and associated utility programs—was proposed by the Public Conference 44 Electric Vehicle Working Group, a consortium led by Baltimore Gas & Electric Company and joined by other utilities and stakeholders.[117]

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[111] Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022, Assigned Commissioner's Amended Scoping Memo and Ruling, Application No. 17-01-012 (CPUC May 18, 2018), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M214/K798/214798344.PDF.

[112] Application of Southern California Edison Company (U 338-E) for Approval of its Charge Ready 2 Infrastructure and Market Education Programs, Application No. 18-06-015 (June 26, 2018), http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/AA563CC19C1B4586882582C200659158/$FILE/A1806015-%20SCE%20Charge%20Ready%202%20Application.pdf.

[113] Honda, *Honda SmartCharge Beta Program Helps Electric Vehicle Drivers Save Money and Reduce Environmental Footprint* (July 31, 2018), http://hondanews.com/releases/honda-smartcharge-beta-program-helps-electric-vehicle-drivers-save-money-and-reduce-environmental-footprint.

[114] The proceeding will consist of two phases: one for evaluation and assessment of the state's current regulatory framework for electric utilities; and a second to explore, among other things, regulatory frameworks that result in incentive-neutral utility decisions between investments in capital and services. *See Instituting Proceeding to Investigate Performance Based Regulation*, Docket No. 2018-0088, Order No. 35411 (Hawaii PUC Apr. 18, 2018), at 1, 5-6, 12-13, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18D18B60624J02464.

[115] *Instituting Proceeding to Investigate Performance Based Regulation*, Docket No. 2018-0088, Order No. 35411 (Hawaii PUC Apr. 18, 2018) at 14, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18D18B60624J02464.

[116] *In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio*, Notice of Initiating a Proceeding and Request for Comments, Case Number 9478 (Maryland PSC Feb. 6, 2018), http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=C:\Casenum\9400-9499\9478\\3.pdf.

[117] PC44 Electric Vehicle Work Group Leader, *Proposal to Implement a Statewide Electric Vehicle Portfolio* (Jan. 19, 2018), https://webapp.psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CAdminDocket%5CPublicConferences%5CPC44%5C95%2Epdf.

Specifically, the group proposes, among other things, to install 24,000 electric vehicle chargers statewide at a cost of $104 million between 2018 and 2023, and to expand existing, and create new, residential time-of-use rates offered by participating utilities.[118]

- **Massachusetts**. In its order approving the grid modernization plans submitted by Eversource, National Grid, and Unitil, the Massachusetts Department of Public Utilities (Massachusetts DPU) declined to approve customer-facing advanced meter investments, noting that the benefits of full advanced meter deployment do not currently justify the costs. The order found that the primary benefits of advanced metering are due to reduced peak demand as customers respond to price signals under time-based rate programs, but that competitive suppliers in the state face several issues regarding the decision to offer time-based rate products. Given this uncertainty, the Massachusetts DPU will begin a process to consider how to remove barriers to the implementation of time-based rate products for all customers.[119]

- **Michigan**. In mid-2018, DTE Energy and Consumers Energy, the two largest utilities in the state, filed separate applications with the Michigan Public Service Commission (MPSC) proposing new time-of-use rates in conjunction with $20.5 million combined investments in electric vehicle infrastructure.[120]

- **Minnesota**. On May 31, 2018, the Minnesota Public Utilities Commission (Minnesota PUC) approved a pilot program for residential time-of-use rates proposed by Xcel Energy.[121] The program is scheduled to begin in early 2020, and will be deployed to 10,000 customers.[122] The program uses an opt-out design and will offer three different rates: an on-peak rate, a mid-peak rate, and an off-peak rate.[123]

- **Nevada**. On May 11, 2018, the Public Utilities Commission of Nevada (Nevada PUC) adopted a rule implementing SB 145 to allow NV Energy to build electric vehicle infrastructure and systems and to administer $15 million in incentives for third-party

[118] *Id*. at Attachment C.
[119] *Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid for Approval by the Department of Public Utilities of its Grid Modernization Plan*, Order Nos.15-120, 15-121, 15-122 (Massachusetts DPU May 10, 2018) at 1-3, https://eeaonline.eea.state.ma.us/EEA/FileService/FileService.Api/file/FileRoom/9163509.
[120] *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief*, Case No. U-20134 (MPSC May 14, 2018) at 7, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000023OKMAA2; and *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*, Case No. U-20162 (MPSC July 6, 2018) at 3-4, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000023OKMAA2.
[121] *In the Matter of Xcel's Residential Time of Use Rate Design Pilot Program*, Docket Nos. E-002/M-17-775, E-002/M-17-776 (Minnesota PUC Aug. 7, 2018) at 8, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90C81565-0000-C411-A2FE-612297DE478D}&documentTitle=20188-145592-01.
[122] *In The Matter of the Petition of Northern States Power Company for Approval of a Time of Use Rate Design Pilot Program*, Petition, Docket No. E-002/M-17-775 (Minnesota PUC Nov. 1, 2017) at 16, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={40D77C5F-0000-C614-A997-18C8C3D839F9}&documentTitle=201711-137092-01.
[123] *Id.* at 19-22.

developers seeking to build such infrastructure.[124] The rule defines electric vehicle infrastructure and systems as consisting of, among other things, vehicle chargers and time-based rates.[125] Additionally, the rule authorizes NV Energy to invest in electric vehicle infrastructure of its own, but specifies that NV Energy may not use the $15 million of incentives for this purpose.[126]

- **Ohio**. On August 29, 2018, the Public Utilities Commission of Ohio (PUCO) released a roadmap as part of its PowerForward initiative that lays out the PUCO's policy positions, principles, and objectives related to the state's grid modernization effort. Among other things, the roadmap considers how the adoption of electric vehicles will potentially affect the operations of the distribution grid. To meet expected growth in electric vehicles, the PUCO anticipates the need for substantial deployment of charging infrastructure as well as the development of rate designs that incent electric vehicle charging during off-peak periods (such as time-of-use rates).[127]

- **Pennsylvania**. In May 2018, the Pennsylvania Public Utility Commission (Pennsylvania PUC) issued a proposed policy statement that identifies factors it will consider in determining just and reasonable distribution rates that promote, among other things, the efficient use of electricity and distributed energy resources.[128] The policy statement discusses a number of alternative rate methodologies that utilities may consider proposing, including time-of-use rates and critical peak pricing.[129]

[124] *Rulemaking to Implement the Provisions of Senate Bill 145 (2017)*, Docket No. 17-08021 (Nevada PUC May 11, 2018), http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-8/29834.pdf.
[125] *Id.* at 11.
[126] *Id*. at 12.
[127] PUCO, *PowerForward: A Roadmap to Ohio's Electricity Future*, at 19-21, https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/powerforward-a-roadmap-to-ohios-electricity-future/.
[128] *Fixed Utility Distribution Rates Policy Statement*, Proposed Policy Statement Order, Docket No. M-2015-2518883 (Pennsylvania PUC May 3, 2018), at 2, http://www.puc.state.pa.us/pcdocs/1568090.docx.
[129] *Id.* at 20-21. *See also Motion of Vice Chairman Andrew G. Place*, Docket No. M-2015-2518883 (Pennsylvania PUC May 3, 2018) at 1-2, http://www.puc.pa.gov/pcdocs/1565057.pdf.

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

The 2009 National Assessment of Demand Response Potential,[130] and previous annual staff reports, describe the barriers to customer participation in demand response. Outstanding barriers and recent actions taken to address them are presented below.

- **Implementing Time-based Rates**. One of the principal barriers to customer participation in demand response is relatively slow implementation of time-based rate programs. As noted in the previous chapter, customer enrollment in time-based rate programs increased by approximately five percent in 2016 from a year earlier primarily due to increased enrollment in programs in the RF and WECC regions. While customer participation in time-based rate programs has increased every year since 2013, only eight million customers are participating in such programs—a relatively small amount.

  In the last year, several state commissions—including those in Minnesota and Pennsylvania—have approved new pilots for, or are considering, time-based rates. Other states are taking additional actions that may result in an expansion in time-based rate programs. The Massachusetts DPU, for example, intends to begin an investigation into removing the barriers to customer adoption of time-based rates as part of the state's grid modernization effort. In addition, utilities in Michigan are proposing time-based rates to assist in managing the integration of electric vehicles into their systems.

  In addition to these regulatory developments, there are nascent technological developments—such as the application of blockchain technology[131] and associated "smart contracts"[132] to the energy sector—that some industry experts believe could support the ability of customers to meaningfully respond to prices. While the most well-known application of the technology is to trade so-called cryptocurrencies such as bitcoin or ether, there is emerging interest among stakeholders in the power sector to apply the technology to electricity transactions at the wholesale and retail levels. In addition, the National Institute of Standards and Technology (NIST) recently published an overview of blockchain technology that briefly discusses examples of use cases for the technology in the power sector.[133]

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

[131] A blockchain is a distributed ledger of transactions that provides a means of recording and verifying such transactions without requiring a central authority to maintain or validate the ledger. *See* David Livingston, et al. (Council on Foreign Relations), *Applying Blockchain Technology to Electric Power System* (July 2018), at 1, https://cfrd8-files.cfr.org/sites/default/files/report_pdf/Discussion_Paper_Livingston_et_al_Blockchain_OR_0.pdf.

[132] A smart contract is a piece of code capable of executing some function within a decentralized ledger. In the context of demand response, a smart contract could, for example, define the behavior of end-use devices during demand response events. *See* Claudia Pop, et al., *Blockchain Based Decentralized Management of Demand Response Programs in Smart Energy Grids,* Sensors 2018, 18, 162 (2018).

[133] Daniel Yaga, et al. (National Institute of Standards and Technology) (2018), *Blockchain Technology Overview (Draft)*, at 39, https://csrc.nist.gov/publications/detail/nistir/8202/draft.

At the wholesale level, for example, Enel, a multinational firm, is conducting research using blockchain technologies in place of proprietary, centralized market clearing software in the European wholesale market, which may lower transaction costs, increase the transparency of transaction data, and allow smaller entities to participate in the wholesale markets and respond directly to wholesale prices.[134] In addition, Texas-based start-up Grid+ is developing a proprietary blockchain-based payment system and an artificial intelligence-enabled "smart agent" device capable of responding directly to wholesale prices and, among other things, controlling end-use technologies such as smart thermostats to provide demand response.[135] Furthermore, utilities such as PG&E, Duke Energy, and Exelon are engaged in initiatives such as the Energy Web Foundation, an industry consortium that aims to apply blockchain technology in the energy sector.[136]

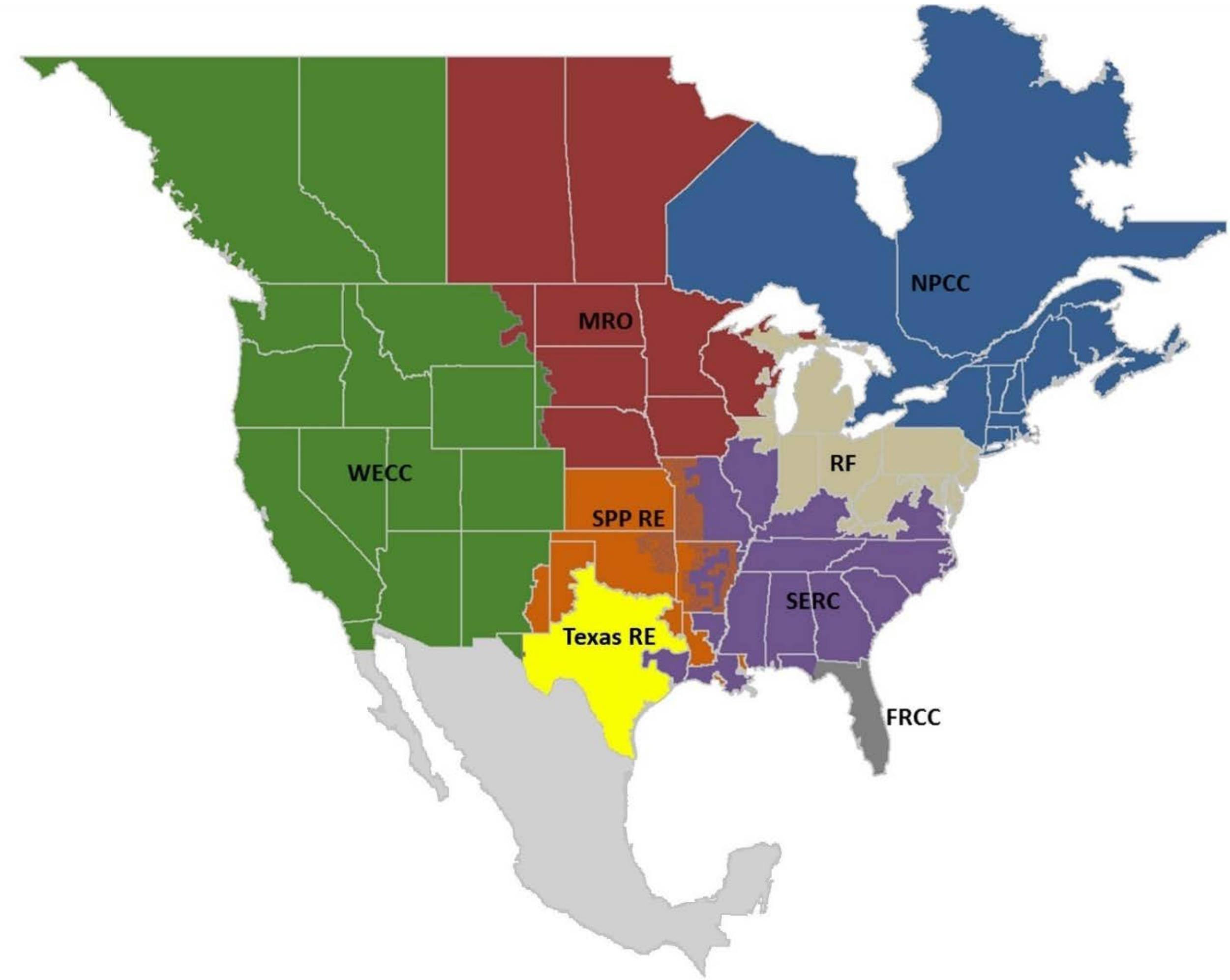
Across industries, almost all blockchain efforts are still in an experimental stage.[137] Power industry experts suggest a range of actions that policymakers might take to support the development of blockchain technology in the electricity sector. In addition to addressing cybersecurity and privacy concerns, these include establishing a process to develop interoperability standards for blockchain technology—perhaps convened by NIST—and allowing new blockchain ventures to pilot ideas and develop demonstration projects in a relaxed regulatory environment on a small scale (i.e., creating a "regulatory sandbox").[138]

- **Consumer Awareness and Engagement**. Surveys indicate that, for the first time, the majority of U.S. consumers have heard of advanced meters (70 percent),[139] figures that have grown significantly since we last reported on this issue in the 2013 staff report.[140] In addition, nearly two-thirds of consumers are interested in receiving energy use information that is provided by advanced meters. Furthermore, 59 percent of those surveyed, and 75 percent of the segment of particularly engaged consumers, are either "probably interested" or "definitely interested" in participating in programs that reward them for reducing electricity use at peak times, such as peak-time rebates.[141] According to research, millenials are particularly interested in these types of programs.[142] This

[134] IEEE Spectrum, *Enerchain: A Decentralized Market on the Blockchain for Energy Wholesalers* (May 25, 2017), https://spectrum.ieee.org/energywise/energy/the-smarter-grid/enerchain-a-decentralized-market-on-the-blockchain-for-energy-wholesalers.
[135] Grid+, *Welcome to the Future of Energy: White Paper* (undated), at 32-33, https://gridplus.io/assets/Gridwhitepaper.pdf. *See also* David Livingston, et al. (Council on Foreign Relations), *Applying Blockchain Technology to Electric Power System* (July 2018), at 15.
[136] Energy Web Foundation, *Affiliates* https://energyweb.org/affiliates/. *See also* David Livingston, et al. (Council on Foreign Relations), *Applying Blockchain Technology to Electric Power System* (July 2018), Appendix Table A-2.
[137] The Economist, *Technology Quarterly: Cryptocurrencies and Blockchains* (Sept. 1, 2018), at 12, https://www.economist.com/technology-quarterly/2018/09/01/dividing-the-cryptocurrency-sheep-from-the-blockchain-goats.
[138] David Livingston, et al. (Council on Foreign Relations), *Applying Blockchain Technology to Electric Power System* (July 2018), at 17-18.
[139] Smart Energy Consumer Collaborative (SECC), *SECC's Customer Pulse and Market Segmentation Study – Wave 6 Summary* https://smartenergycc.org/research/secc-research/sgccs-consumer-pulse-and-market-segmentation-study-wave-6-summary/.
[140] FERC, *Assessment of Demand Response and Advanced Metering* (2013), https://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.
[141] SECC, *2018 State of the Consumer—Executive Summary*, https://smartenergycc.org/research/secc-research/seccs-2018-state-of-the-consumer-report-summary/. *See also* SECC, *Consumer Pulse and Market Segmentation Study - Wave 6, Executive Summary*, at 6, https://smartenergycc.org/research/secc-research/sgccs-consumer-pulse-and-market-segmentation-study-wave-6-summary/.
[142] SECC, "SECC Research Brief: 2018 State of the Consumer," (Mar. 20, 2018 webinar), https://vimeo.com/261003662.

research suggests that understanding the needs and degree of engagement of different consumer segments may be important to the success of demand response and time-based rate programs that leverage data from advanced meters.

Appendix: Map of NERC Regional Entities (as of May 2017)



Note: On May 4, 2018, FERC approved a joint petition to transfer NERC registered entities within the SPP RE footprint to MRO and SERC. *See NERC, MRO and SERC*, 163 FERC ¶ 61,094 (2018). A current map of NERC registered entities is here: https://www.nerc.com/AboutNERC/keyplayers/PublishingImages/Regions24JUL18.jpg.

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