2020 Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

December 2020

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

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

FEDERAL ENERGY REGULATORY COMMISSION

Acknowledgements

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1. Introduction

This report is the Federal Energy Regulatory Commission (Commission) staff's fifteenth annual report on demand response and advanced metering, as 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 that is used to estimate demand response potential in the retail and wholesale markets and non-public data.[1]

Highlights of the report include the following:

- Advanced meters[2] continue to be the most prevalent type of metering deployed throughout the United States. From 2017 to 2018, the number of advanced meters in operation in the United States increased by 7.9 million to a total of 86.8 million. According to Energy Information Administration (EIA) data,[3] the 86.8 million advanced meters operational out of the 154.1 million meters in the United States represents a 56.4% penetration rate.

- While the advanced meter penetration rate varies by customer class, in 2018 the estimated nationwide advanced meter penetration rates for each of the residential, commercial, and industrial customer classes were greater than or equal to 50% for the first time.

- In 2018, utilities in ReliabilityFirst reported 21.6 million advanced meters in operation. From 2013 to 2018, the number of advanced meters deployed by utilities in ReliabilityFirst has almost tripled.

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[1] The latest publicly available retail data for the report is for the year 2018 while the latest publicly available wholesale data is for the year 2019. In addition to publicly available data for demand response potential in retail and wholesale markets, this report contains findings of Commission staff using non-public data to evaluate demand response performance in California during summer 2020 events.

[2] As defined by the 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 meter reading (AMR) meters, which collect data for billing purposes only and transmit this data one way—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.

[3] EIA, *2018 Annual Electric Power Industry Report Form EIA-861* (Mar. 16, 2020), https://www.eia.gov/electricity/data/eia861/.

- Since the last report was issued, electric utilities in states across the country—including Missouri, New Jersey, and New Mexico—introduced new proposals or were granted permission to submit proposals for advanced meter deployments. In general, state regulators are requesting or requiring greater justification from utilities for investments in advanced meters, and requiring utilities' advanced meter plans to clearly demonstrate how advanced meters will produce customer savings, identify and mitigate system outages, and facilitate more dynamic rate offerings, as seen in proceedings in North Carolina and Virginia.

- In 2018, customer enrollment in retail incentive-based demand response programs and retail dynamic pricing programs increased by 311,300 customers and 722,149 customers, respectively. Total enrollment in both types of programs was greater than nine million customers in 2018. Retail dynamic rate designs continue to incorporate distributed energy resources and electric utilities are increasingly exploring their impact on demand response and dynamic pricing programs while also crafting specific rates and rate programs for electric vehicles owned by residential customers.

- From 2018 to 2019, demand resource participation in the wholesale markets increased by approximately 2,734 MW, or nine percent, to a total of 32,408 MW. In 2019, for the first time since 2015, SPP reported demand response capability in its markets and introduced tariff changes to allow for demand response resources and behind-the-meter generation to meet resource adequacy requirements.

This 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 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).

2. Saturation and Penetration Rate of Advanced Meters

This chapter reports the penetration rate for advanced meters as well as state developments related to grid modernization and advanced metering. As summarized in Table 2-1 and Figure 2-1, advanced meters are the most prevalent type of metering deployed in the United States. In 2018, according to EIA data,[4] there were 86.8 million advanced meters installed and operational out of the 154.1 million meters installed and operational nationwide, representing a 56.4% penetration rate and a total increase of 7.9 million advanced meters from 2017 to 2018, as shown in Table 2-1. Data from the Edison Foundation's Institute for Electric Innovation indicates a similar level and penetration rate for advanced meters.

[4] EIA, Form EIA-861: Advanced_Meters_2018 data file (original release Oct. 1, 2019 and re-released Mar. 16, 2020).

Table 2-1: Estimates of Advanced Meter Penetration Rates

Data Source	Data As Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2008 FERC Survey	Dec 2007 (FERC)	6.7 [1]	144.4 [1]	4.7%
2010 FERC Survey	Dec 2009 (FERC)	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec 2011 (FERC)	38.1 [3]	166.5 [3]	22.9%
2011 Form EIA-861	Dec 2011 (EIA)	37.3 [4]	144.5 [4]	25.8%
Institute for Electric Efficiency	May 2012 (IEE)	35.7 [5]	144.5 [5]	24.7%
2012 Form EIA-861	Dec 2012 (EIA)	43.2 [6]	145.3 [6]	29.7%
Institute for Electric Innovation	July 2013 (IEI)	45.8 [7]	145.3 [7]	31.5%
2013 Form EIA-861	Dec 2013 (EIA)	51.9 [8]	138.1 [8]	37.6%
Institute for Electric Innovation	July 2014 (IEI)	50.1 [9]	138.1 [9]	36.3%
2014 Form EIA-861	Dec 2014 (EIA)	58.5 [10]	144.3 [10]	38.8%
2015 Form EIA-861	Dec 2015 (EIA)	64.7 [11]	150.8 [11]	42.9%
Institute for Electric Innovation	Dec 2015 (IEI)	65.6 [12]	150.8 [12]	43.5%
2016 Form EIA-861	Dec 2016 (EIA)	70.8 [13]	151.3 [13]	46.8%
Institute for Electric Innovation	Dec 2016 (IEI)	72.0 [14]	151.3 [14]	47.6%
2017 Form EIA-861	Dec 2017 (EIA)	78.9 [15]	152.1 [15]	51.9%
2018 Form EIA-861	Dec 2018 (EIA)	86.8 [16]	154.1 [16]	56.4%
Institute for Electric Innovation	Dec 2018 (IEI)	88.0 [17]	154.1 [17]	57.1%

Sources: [1] FERC, *Assessment of Demand Response and Advanced Metering* (FERC DR AM Staff Report) (2008). [2] FERC DR AM Staff Report (2011). [3] FERC DR AM Staff Report (2012). [4] 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 (IEE), *Utility-Scale Smart Meter Deployments, Plans & Proposals* (2012). [6] EIA-861 and EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (Oct. 29, 2013). [7] The Edison Foundation Institute for Electric Innovation (IEI), *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits* (2013). [8] EIA-861: Advanced_Meters_2013 data file (re-released Jun. 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-861 Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf. [9] IEI, *Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid* (2014). [10] EIA-861: Advanced_Meters_2014 data file (re-released Jan. 13, 2016). [11] EIA-861: Advanced_Meters_2015 data file (re-released Nov. 1, 2016). [12] IEI, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (2016). EIA-861: Advanced_Meters_2016 data file (re-released Nov. 6, 2017). [14] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2017). [15] EIA-861: Advanced_Meters_2017 data file (re-released Jan. 15, 2019). [16] EIA-861: Advanced_Meters_2018 data file (originally released October 2019, re-released Mar. 16, 2020). [17] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2019). The IEI report only lists the total number of advanced meters.

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

Figure 2-1 shows the growth of advanced meters from 2007 through 2018. According to EIA data, over this period, the number of advanced meters in operation has increased almost thirteen-fold in the United States from 6.7 million meters to more than 86.8 million meters. Between 2017 and 2018, approximately 8 million additional advanced meters were installed nationwide, resulting in a 4.5% increase in the advanced meter penetration rate, from 51.9% in 2017 to 56.4% in 2018.

Figure 2-1: Advanced Meter Growth (2007–2018)

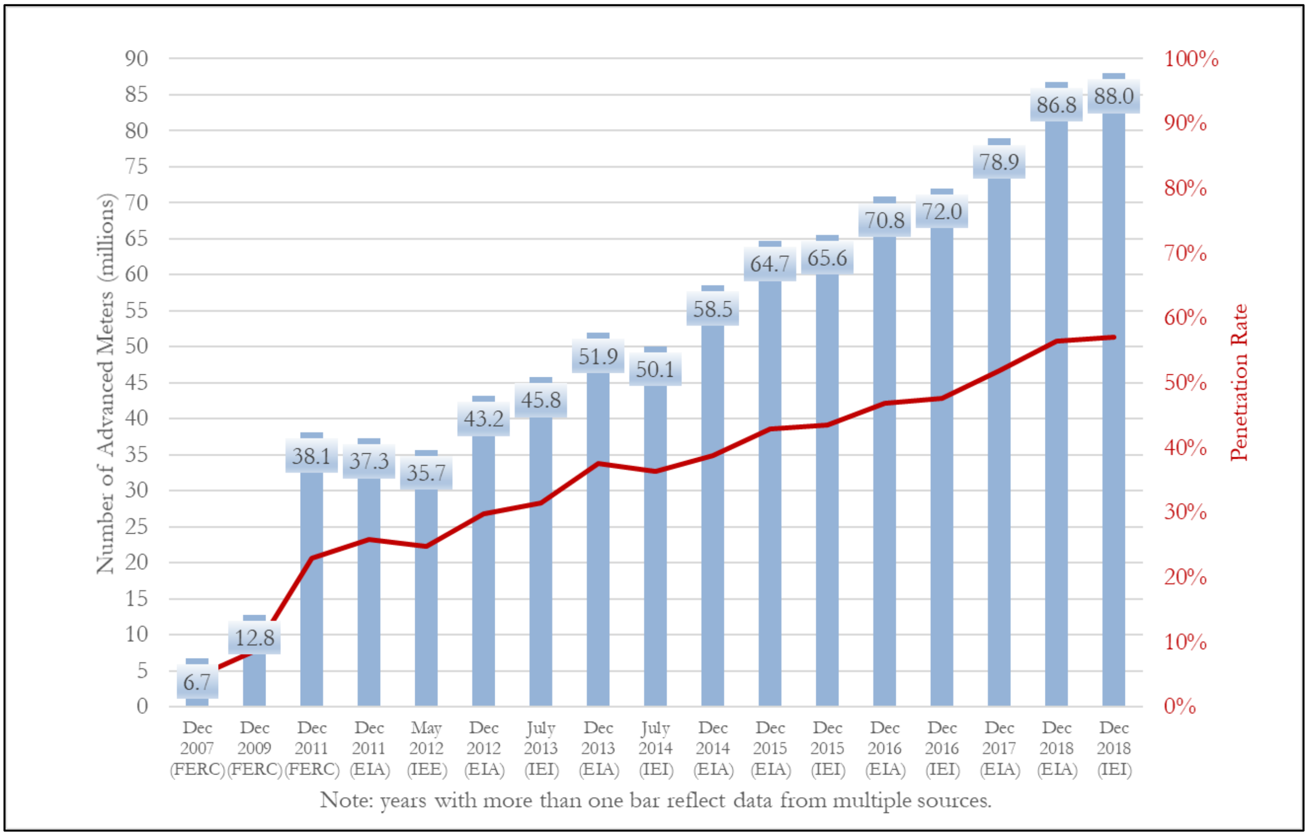


Table 2-2 below provides estimated advanced meter penetration rates by North American Electric Reliability Corporation (NERC) region, as well as for Alaska and Hawaii,[5] and by retail customer class. Data

[5] For the time period examined (i.e., through 2018), 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 and Hawaii are not subject to NERC oversight. Note that, with the dissolution of SPP RE and FRCC in 2018 and 2019, respectively, there are currently six NERC Regional Entities. *See* Appendix; *see also* NERC, "NERC Regions Map," (Dec. 15, 2017), https://www.nerc.com/pa/comp/RegistrationNewsDL/SPP%20RE%20Transition%20Additional%20Information%20Regarding%20NERC%27s%20Proposed%20Transferee%20Regional%20Entities.pdf. On

for 2018 indicates that six of the eight NERC regions, as well as Alaska, had advanced meter penetration rates above 50%. Approximately 93% of all Texas RE meters, 66% in both SPP RE and Alaska, 65% in WECC, 62% in FRCC and ReliabilityFirst, and approximately 55% in SERC are advanced meters. The largest absolute growth in advanced meters from 2017 to 2018 occurred in ReliabilityFirst, SERC, and WECC where over 2.2 million, 1.9 million, and 1.5 million additional advanced meters, respectively, went into operation. Annual increases of over 450,000 advanced meters were also reported in FRCC, MRO, and Texas RE. The highest percentage growth in advanced meters from 2017 to 2018 occurred in Alaska and MRO, with increases of 53% and 28%, respectively.

Table 2-2 below also provides the advanced meter penetration rates for the residential, commercial, and industrial customer classes. In 2018, the estimated advanced meter penetration rate for each of the customer classes was greater than or equal to 50% for the first time. Table 2-2 indicates that, nationally, advanced meters are slightly more common among residential and commercial sectors on a percentage basis compared to the industrial sector. In 2018, advanced meters accounted for approximately 57% of all residential meters, 54% of all commercial meters, and 51% of all industrial meters, resulting in a combined 56% penetration rate for all three customer classes across the United States. Within regions, there is noticeable variation in advanced meter penetration by customer class. For example, in five of the eight NERC regions (i.e., ReliabilityFirst, SERC, SPP RE, Texas RE, WECC), as well as in Alaska, the residential sector has a higher advanced meter penetration rate than the commercial or industrial sector. In contrast, the advanced meter penetration rate in FRCC, MRO, NPCC, and Hawaii, is highest in the industrial sector.

May 4, 2018, FERC approved a joint petition to dissolve the SPP RE and transfer NERC registered entities within the SPP RE footprint to MRO and SERC, effective July 1, 2018. *See NERC, MRO and SERC*, 163 FERC ¶ 61,094 (2018). However, because the dissolution of SPP RE was not final until August 2018, many utilities still reported to EIA SPP RE as the relevant NERC region. Commission staff presents its findings as they were reported to EIA.

Table 2-2: Advanced Meter Penetration Rate by Customer Class and Region (2018)

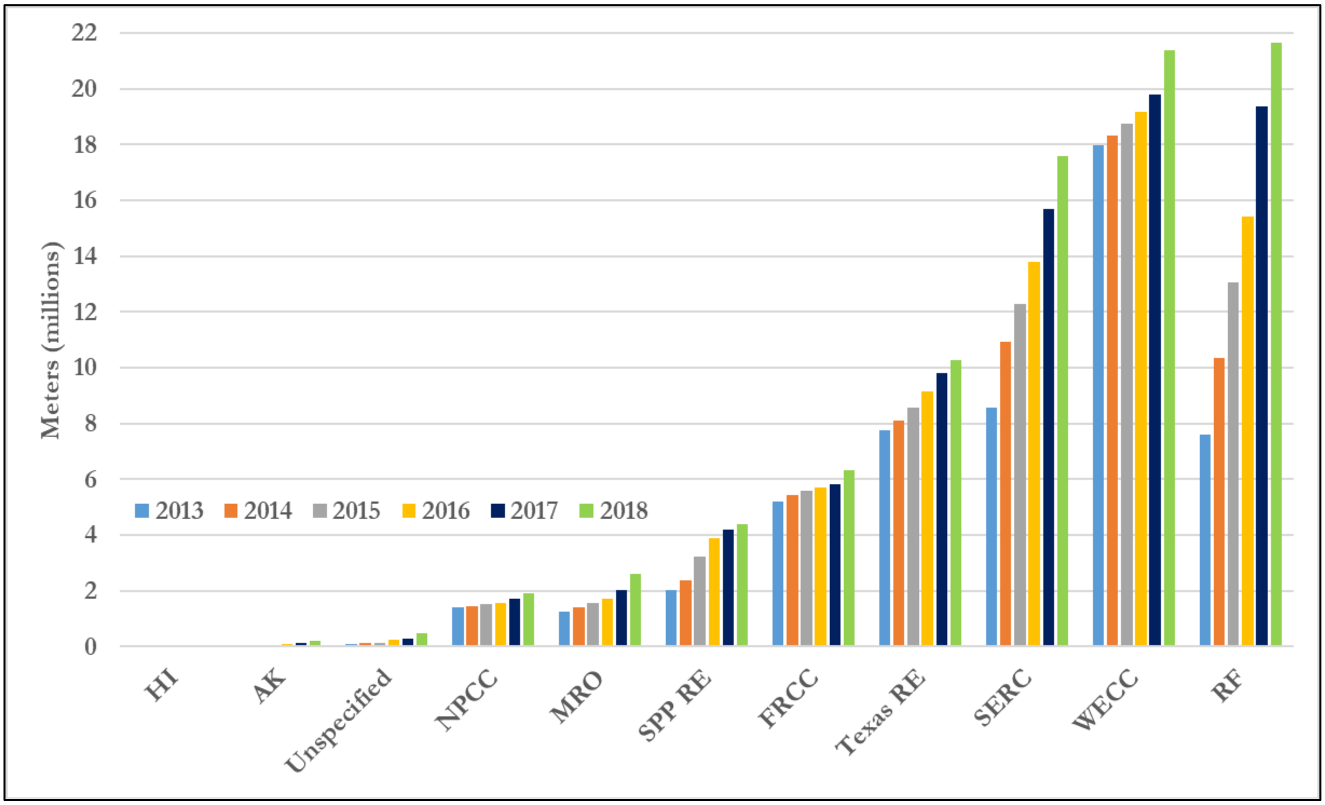
Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
Alaska	68.9%	52.0%	63.0%	66.4%
FRCC	61.4%	65.1%	73.6%	61.9%
Hawaii	6.2%	7.7%	15.5%	6.4%
MRO	31.5%	28.2%	46.7%	31.3%
NPCC	12.3%	11.9%	20.5%	12.2%
ReliabilityFirst	62.6%	57.7%	43.3%	62.0%
SERC	55.2%	50.7%	40.7%	54.6%
SPP RE	66.4%	62.2%	63.9%	65.7%
Texas RE	93.3%	90.1%	59.8%	92.8%
WECC	65.2%	63.5%	56.0%	64.9%
Unspecified	40.4%	42.9%	36.7%	40.7%
All Regions	**56.7%**	**54.0%**	**50.8%**	**56.4%**

Source: 2018 Form EIA-861 Advanced_Meters_2018 data file, 2018 Form EIA-861 Utility_Data_2018, 2017 Form EIA-861 Advanced_Meters_2017 data file, 2017 Form EIA-861 Utility_Data_2017.

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 below displays the number of advanced meters in operation by NERC region from 2013 to 2018. In 2018, all NERC regions experienced increases in the number of advanced meters in operation, and four NERC regions—ReliabilityFirst, SERC, Texas RE, and WECC—realized totals of over 10 million advanced meters in operation in their respective regions. In 2018, utilities in ReliabilityFirst reported an estimated 21.6 million advanced meters in operation. This is the first time since 2013 that a region other than WECC had the highest number of advanced meters in operation. Utilities in WECC reported 21.3 million advanced meters. The total in ReliabilityFirst also reflects a larger overall growth trend in comparison to other NERC regions. In 2013, ReliabilityFirst had 7.6 million advanced meters in operation, indicating that roughly 14 million advanced meters were installed in the following five years, resulting in a 184% increase from 2013 to 2018.

Figure 2-2: Number of Advanced Meters by Region (2013–2018)



Within ReliabilityFirst, where the number of advanced meters increased by approximately 2.3 million from 2017 to 2018, Ohio Power Company reported an increase of over 483,000 advanced meters, the largest annual change for a utility in the region. In SERC, the total reported increase in advanced meters from 2017 to 2018 was approximately 1.9 million; of this, the largest annual increases were reported by Duke Energy Carolinas with 799,000 additional advanced meters and Ameren Illinois with 367,000 additional advanced meters. Finally, in WECC, where the total reported increase was approximately 1.6 million meters, PacifiCorp reported an increase of 517,000 advanced meters, the City of Seattle reported an increase of 336,000 advanced meters, and Puget Sound Energy Inc. reported an increase of 184,000 advanced meters. Large aggregate increases of 574,000 advance meters, 478,000 advanced meters, 456,000 advanced meters, and 207,000 advanced meters were also reported by utilities in MRO, FRCC, Texas RE, and NPCC, respectively.

Developments and Issues in Advanced Metering

State Legislative and Regulatory Activity Related to Advanced Metering

Generally, initial advanced meter proposals touted the cost savings from avoided labor-intensive manual meter reading and the need to replace aging legacy meter infrastructure that had reached the end of its useful life. Now, as distribution systems continue to evolve and become more complex (e.g., the addition of customer-sited distributed energy resources), the regulatory review and approval process often considers how utilities can use the improved sensing and measuring capabilities of advanced meters to improve operations and use distributed solutions to provide grid services and deliver cost savings for customers.[6] In general, state regulators are requesting or requiring greater justification from utilities for investments in advanced meters to ensure their capabilities are fully leveraged. Additional justifications for new investments have included improved customer access to data, increased capabilities to monitor and optimize system operations, greater engagement with customers, enhancement of dynamic pricing programs,[7] and better outage coordination.[8] In some cases, state regulators have required utilities to revise and improve their proposals to maximize customer engagement and justify costs. Electric utilities in states across the country continue to propose and receive approval for programs involving advanced meters. Here we summarize recent legislative and regulatory activity by state.

- **California.** In December 2019, Riverside Public Utilities selected an advanced meter provider for its 320,000 residents,[9] stating that the deployment of advanced meters will give customers access to energy usage through an online portal, allow customers to establish usage threshold alerts, and eventually allow for time-of-use rates.[10] The project is expected to cost $14 million and Riverside Public Utilities expects an internal rate of return of 26.4% over seven years.[11]

- **Massachusetts.** On July 2, 2020, the Massachusetts Department of Public Utilities (Massachusetts DPU) opened a grid modernization proceeding to investigate deployment of

[6] For a more comprehensive discussion of interoperability (the capability of two or more networks, systems, devices, applications, or components to work together, and to exchange and readily use information), see NIST, *DRAFT - Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0* (2020), https://www.nist.gov/system/files/documents/2020/07/24/Smart%20Grid%20Draft%20Framework.pdf.

[7] *For Approval Of Plan For Electric Distribution Grid Transformation Projects Pursuant To § 56-585.1 A 6 Of The Code Of Virginia, And Approval Of An Addition To The Terms & Condition Applicable To Electric Service*, Final Order, Case No. PUR-2019-00154 (SCC Mar. 26, 2020) at 4, https://www.scc.virginia.gov/getattachment/bc18c944-0c12-4afb-9402-6c9d16ccec05/r_domgrid_20.pdf.

[8] New Jersey Board of Public Utilities, *2019 Energy Master Plan: Pathway to 2050*, 184-189, https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf.

[9] Tantalus, "Riverside Public Utilities Selects Tantalus, Joins Growing Community of Public Power and Electric Cooperative Utilities Seeking Digital Transformation" (Dec. 19, 2019), https://www.tantalus.com/2019/12/19/riverside-public-utilities-selects-tantalus-joins-growing-community-of-public-power-and-electric-cooperative-utilities-seeking-digital-transformation/.

[10] Riverside Public Utilities, *Advanced Metering Infrastructure (AMI) Business Case Summary* (2019), at 1-2, http://www.riversidepublicutilities.com/projects/pdf/AMI%20Business%20Case%20Summary%20vFINAL.pdf.

[11] *Id.* at 2-4.

advanced meters to support retail electric vehicle customers and electric vehicle charging hosts.[12] Noting that electric vehicle customers are a currently a small but rapidly growing customer segment, the Massachusetts DPU stated that a targeted deployment of advanced metering functionality[13] to electric vehicle customers will help establish the groundwork for additional advanced metering functionality to other customer segments.[14] This is in contrast to a decision in 2018, as part of a previous inquiry into grid modernization,[15] to not preauthorize any of the utilities' proposals to install advanced meters because it would require the utilities to prematurely retire their existing meters at a significant cost, while the benefits remained uncertain especially without wide customer adoption of time-based rates. The Massachusetts DPU also stated that it will investigate potential dynamic pricing designs for electric vehicle customers to achieve the benefits of advanced meters.[16]

- **Missouri.** On February 26, 2020, Ameren Missouri submitted its updated five-year capital investment plan and provided the Missouri Public Service Commission with a report on investments made in 2019 pursuant to its previous capital investment plan.[17] Ameren Missouri

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[12] *Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two*, Docket No. 20-69 (Massachusetts DPU July 2, 2020), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12334560.

[13] As defined by the Massachusetts DPU, advanced metering functionality includes: (1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage restoration and notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of a customer's appliances. See *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, Docket No. 12-76 (Massachusetts DPU June 12, 2014) at 15, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9235208.

[14] *Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two*, Docket No. 20-69 (Massachusetts DPU July 2, 2020) at 6, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12334560.

[15] *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.*, Order Nos. 15-120, 15-121, 15-122 (Massachusetts DPU May 10, 2018), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163509.

[16] *Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two*, Docket No. 20-69 (Massachusetts DPU July 2, 2020) at 6-7, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12334560.

[17] *In the Matter Of The Compliance Of Union Electric Company D/B/A Ameren Missouri, With Certain Requirements Related To Sb 564 And Related Matters*, Ameren Missouri's Five-Year Capital Investment Plan, Docket No. EO-2019-0444 (Missouri PSC Feb. 26, 2020),

proposes to spend approximately $279 million on its Smart Meter Program through 2024 and proposes to fully deploy advanced meters across its Missouri service territory by 2025. Ameren Missouri is also investing in automated, self-healing grid equipment to reduce the frequency and duration of outages and developing alterative rate options to enhance customer choice.[18]

- **New Jersey.** On February 19, 2020, the New Jersey Board of Public Utilities (NJBPU) found that advanced meters provide potential distribution system benefits, streamline and modernize utility operations, provide an enhanced customer experience, benefit the environment, and, as a result, directed each of the state's distribution utilities to file petitions for advanced meter deployments.[19] In response to the NJBPU's directive, Public Service Electric and Gas (PSEG) submitted an updated proposal seeking approval for their "Clean Energy Future – Energy Cloud" program.[20] If approved, 2.3 million advanced meters would be deployed for all PSEG electric customers over a five-year period at a cost of approximately $714 million.

- **New Mexico.** On March 3, 2020, the Governor of New Mexico signed legislation creating a framework to modernize New Mexico's electric grid.[21] The legislation directs the New Mexico Department of Energy, Minerals, and Natural Resources (New Mexico Energy Department) to develop a roadmap and competitive grant program for grid modernization, which includes advanced meters and advanced metering infrastructure. The legislation also allows investor-owned utilities to submit applications to the New Mexico Public Regulations Commission for review and approval of investments in grid modernization projects.

- **North Carolina.** On July 29, 2019, the North Carolina Utilities Commission (North Carolina Commission) approved a previously directed re-design of Duke Energy Carolinas' rate structures

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https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2019-0044&attach_id=2020013299.

[18] Ameren Missouri, *Overview of Ameren Missouri's Smart Energy Plan*, Presentation to Missouri PSC (June 17, 2020), https://psc.mo.gov/CMSInternetData/Agenda%20Presentations/2020%20Presentations/6-17-20%20Ameren%20Missouri%20Smart%20Energy%20Plan%20Presentation.pdf.

[19] *In The Matter Of The Petition Of Rockland Electric Company For Approval Of An Advanced Metering Program; And For Other Relief*, Decision and Order, Docket No. ER16060524 (NJBPU Feb. 19, 2020) at 3, https://www.state.nj.us/bpu/pdf/boardorders/2020/20200219/2-19-20-2D.pdf.

[20] *See In The Matter Of The Petition Of Public Service Electric And Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("Cef-Ec") Program On A Regulated Basis*, Docket No. EO18101115, (NJBPU Apr. 1, 2020) at 4-5, https://nj.pseg.com/aboutpseg/regulatorypage/-/media/AD4593BE38334E57A887C622FC08574E.ashx.

[21] Energy Grid Modernization Roadmap, HB 233, New Mexico Legislature (2020), https://nmlegis.gov/Legislation/Legislation?Chamber=H&LegType=B&LegNo=233&year=20.

to capture the full benefits of its advanced meter installations.[22] Under the new rate structures, Duke Energy Carolinas will use data from deployed advanced meters to populate information on a website that allows customers to access their meter data and facilitate bill comparisons in order to select a rate schedule most suited to their need.[23]

Additionally, on November 13, 2019, the North Carolina Commission eliminated a requirement that investor-owned utilities submit five-year Smart Grid Technology Plans within their biennial integrated resource plans.[24] The North Carolina Commission concluded that the Smart Grid Technology Plans have served their intended purpose, and the burden on the utilities now outweigh the benefits due especially to the "fast pace of renewables development and technology changes."[25]

- **Texas.** On April 20, 2020, the Public Utilities Commission of Texas (PUCT) adopted amendments to the state administrative code pertaining to advanced metering.[26] The PUCT found there was an increasing interest in more on-demand readings from customers' advanced meter data, and limited interest in real-time information sharing from home area networks. Thus, the PUCT retained the requirement that electric utilities have the continuous capability to provide on-demand readings of customers' advanced meter data, while removing requirements to offer home area networks.[27] In addition to the data sharing rules, the PUCT also authorized cost recovery for utilities outside of the ERCOT region to deploy advanced meters. Utilities impacted by the authorization include El Paso Electric, Entergy Texas, Southwestern Electric Power Company, and Southwestern Public Service Company.

- **Virginia.** On September 30, 2019, Dominion Energy (Dominion) filed a ten-year grid transformation plan with the Virginia State Corporation Commission (SCC). Dominion's plan was projected to cost approximately $838 million in the first three years and approximately

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[22] *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 (North Carolina Commission July 29, 2019), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=6cceef45-40ae-441e-8b01-a57f6f76c74e.

[23] *Id.* at 1.

[24] *In the Matter of Investigation of Integrated Resource Planning in North Carolina – Smart Grid Technology Plans*, Docket No. E-100 sub 126 (North Carolina Commission Nov. 13, 2019), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=e414402a-cbf9-43f0-a315-835f02b2be19.

[25] *Id.* at 2.

[26] *Rulemaking Related to Advanced Metering*, Project No. 48525 (PUCT Apr. 20, 2020), http://interchange.puc.texas.gov/Documents/48525_45_1061856.PDF.

[27] *Id.* at 14.

$7 billion over ten years.[28] Dominion also proposed to spend approximately $84 million over the first three years to develop a customer information platform.[29] As part of the plan, Dominion proposed to fully deploy advanced meters across its Virginia service territory at a cost of $304 million over the first three years and $753 million over ten years.[30] On March 26, 2020, the SCC rejected without prejudice the advanced meter and associated infrastructure component of Dominion's grid transformation plan. The SCC reasoned that Dominion's proposal did not maximize the full potential of advanced meters and did not justify the substantial cost to consumers since the utility did not submit a comprehensive plan to roll out time-varying rates as part of its advance metering proposal.[31]

Collaborative Industry-Government Efforts

On January 30, 2020, the North American Energy Standards Board (NAESB), with the Green Button Alliance,[32] published the latest revision to the NAESB Retail Energy Quadrant Book 21 (REQ.21) Energy Services Provider Interface (ESPI) Model Business Practices standards, also known as Green Button *Connect My Data*. The changes updated security requirements, created a Retail Customer data structure, and added a use case for a "Download My Data" function, among other updates.[33]

In May 2020, the National Renewable Energy Laboratory (NREL) and the Rocky Mountain Institute published a report discussing potential energy management approaches for Connected Communities and their benefits for customers, utilities, and system operators. Connected Communities are described as "collections of buildings and distributed energy resources that incorporate integrated energy management

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[28] *For Approval of a Plan for Electric Distribution Grid Transformation Projects pursuant to § 56-585.1 A 6 of the Code of Virginia, and Approval of an Addition to the Terms & Conditions Applicable to Electric Service*, Final Order, Case No. PUR-2019-00154 (SCC Mar. 26, 2020) at 4, https://www.scc.virginia.gov/getattachment/bc18c944-0c12-4afb-9402-6c9d16ccec05/r_domgrid_20.pdf.

[29] *Id.* at 4, n.7.

[30] *Id.* at 4. Dominion notes that it has already deployed approximately 485,000 advanced meters through the end of 2019. *See Id.* at 8, n.19.

[31] *Id.* at 8-9.

[32] The Green Button Alliance is an industry-led effort to provide electricity customers with easy access to their energy usage data in a standardized, simple-to-understand format accessible from personal electronic devices and computers. *See* Green Button Alliance, "What is the Green Button initiative?," https://www.greenbuttonalliance.org/about#what.

[33] Green Button Alliance April Newsletter, "April Newsletter: NAESB Publishes Enhanced Standard for Green Button" (April 2020), https://www.greenbuttonalliance.org/newsletters-archive; NAESB, "NAESB Bulletin Volume 12, Issue 3" (Dec. 2019 – Feb. 2020) at 4, https://naesb.org//pdf4/naesb_bulletin_vol12_issue3.pdf.

strategies at the multi-building scale" and are consistent with the Department of Energy's framework for grid-interactive efficient buildings.[34] The NREL report found that dynamic rate schedules, and the necessary infrastructure for them, such as advanced meters, are critical for aligning the customer and utility-side benefits when operating Connected Communities.[35] The report provided examples of existing Connected Communities in the United States.[36] Additionally, the report discussed aggregate loads in which buildings and distributed energy resources are connected together virtually with central controls to allow communications between distributed generation systems and building automation systems associated with load shedding and flexible demand capacity.[37]

Connected Communities exhibit four key characteristics: (1) grid-interactive buildings that can modify their energy use in response to grid signals; (2) multiple technologies, such as building load flexibility and distributed energy resources; (3) the ability to manage and/or optimize energy resources of multiple buildings; and (4) physically connected, shared systems to take advantage of economies of scale and balance loads across buildings.[38] The report contended that Connected Communities can enable energy bill savings through demand reductions, aggregation of larger loads for participation in demand response programs, and can reduce capacity requirements for transmission and distribution infrastructure. The report noted the potential value of Connected Communities, proposed ways to unlock this potential value, and discussed the market and technical challenges for Connected Communities.

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[34] National Renewable Energy Laboratory, *Connected Communities: A MultiBuilding Energy Management Approach* (May 2020) at v, https://www.nrel.gov/docs/fy20osti/75528.pdf; *See* Department of Energy, *Grid-Interactive Efficient Buildings*, https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings.

[35] National Renewable Energy Laboratory, *Connected Communities: A MultiBuilding Energy Management Approach* (May 2020) at 18, https://www.nrel.gov/docs/fy20osti/75528.pdf.

[36] *Id.* at 41.

[37] *Id.* at 44.

[38] *Id.* at 2.

3. Annual Resource Contribution of Demand Resources

This chapter summarizes the annual potential resource contribution from retail and wholesale demand response programs on a national and regional basis using the latest publicly available data from EIA and regional transmission organizations (RTO) and independent system operators (ISO).[39]

Retail Demand Response Programs

Table 3-1 presents data collected by EIA from utilities in the eight NERC regional entities, as well as Alaska and Hawaii, on potential peak demand savings from retail demand response programs by customer class.[40] The term "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."[41] Nationwide, total potential peak demand savings from retail demand response programs decreased slightly by 612.5 MW, or 1.9%, from 31,507.5 MW in 2017 to 30,895 MW in 2018, as shown in Table 3-1. SERC and ReliabilityFirst continue to be the NERC regions with the greatest potential peak demand savings reported by utilities for retail demand response programs, as seen in Table 3-1 and Figure 3-1 below.

[39] The latest publicly available retail and wholesale data sets used to determine the annual (changes in) resource contributions from demand response programs include EIA retail data for 2017 and 2018, as well as RTO/ISO wholesale data for 2018 and 2019.

[40] For the time period examined (i.e., through the end of 2018), NERC was comprised of eight regional entities. Commission staff presents its findings as they were reported to EIA, *see supra* n.5. Potential peak demand savings from retail demand response programs are categorized by NERC region because programs exist in regions both with and without organized wholesale markets.

[41] For 2018, Form EIA 861S, or short form, was used to collect data to decrease the reporting burden on utilities but does not define "potential peak demand savings". Once every eight years, the full form EIA 861 must be completed. Form EIA 861 defines "[p]otential peak demand savings" that Commission staff uses to report potential demand resource contributions. Form EIA 861 data that Commission staff uses continues to report "potential peak demand savings."

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Region (2018)

Region	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2017	2018	MW	%
AK	27.0	27.0	0.0	0.0%
FRCC	3,112.4	3,097.9	-14.5	-0.5%
HI	32.6	34.4	1.8	5.5%
MRO	5,364.5	5,252.7	-111.8	-2.1%
NPCC	821.4	1,058.7	237.3	28.9%
ReliabilityFirst	6,171.0	5,899.0	-272.0	-4.4%
SERC	8,787.9	8,452.9	-335.0	-3.8%
SPP RE	1,700.4	1,686.8	-13.6	-0.8%
Texas RE	823.8	914.0	90.2	10.9%
WECC	4,553.7	4,382.6	-171.1	-3.8%
Unspecified	112.8	89.0	-23.8	-21.1%
Total	**31,507.5**	**30,895.0**	**-612.5**	**-1.9%**

Sources: EIA, EIA-861 Demand_Response_2017, Demand_Response_2018, Utility_Data_2017, and Utility_Data_2018 data files. No NERC regions reported any savings in the Transportation customer class.

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.

The slight decrease from 2017 to 2018 in potential peak demand savings from retail demand response programs was the result of small reductions in six of the eight NERC regions. The largest decreases were reported in SERC, ReliabilityFirst, and WECC, in which utilities reported aggregate decreases of 335 MW, 272 MW, and 171 MW, respectively. Notable increases in total potential peak demand savings were reported in the NPCC and the Texas RE regions. Utilities in NPCC, which covers New York and New England in the United States, reported an increase in potential peak demand savings from retail demand response programs of 237 MW, or a 29% increase in retail potential peak demand savings, which is primarily attributable to a 100 MW increase reported by Niagara Mohawk Power Corporation. The 90 MW increase in Texas RE from 2017 to 2018 is a 10.9% increase in retail potential peak demand savings, attributable to Austin Energy and the City of San Antonio. In WECC, despite a regionwide decrease, large utility-specific increases were reported by Pacific Gas & Electric (PG&E) and Public Service Company of Colorado (PSCo). Figure 3-1 below shows the changes in potential peak demand savings by NERC region since 2013.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Region (2013–2018)

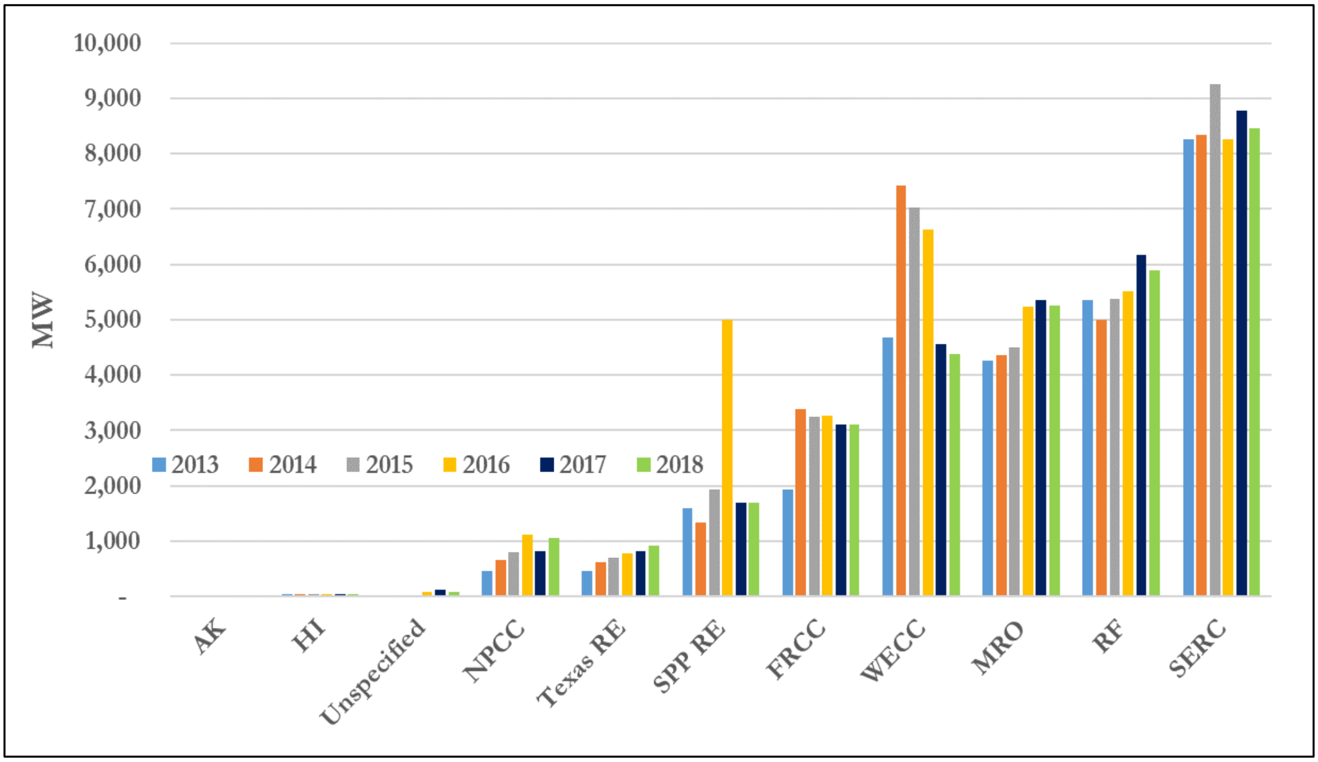

Table 3-2 below provides the relative contribution of potential peak demand savings for retail demand response programs in 2018. In five of the NERC regions, the industrial customer class reported the greatest potential peak demand savings. The industrial sector provided approximately 15,335 MW, or 50%, of potential peak demand savings from all customer classes in 2018. With respect to the individual NERC regions, the SERC region had the largest amount of potential peak demand savings from industrial demand response programs with approximately 5,941 MW. Moreover, in 2018, SERC-located industrial demand response programs contributed nearly 39% to the total reported industrial peak demand savings for all regions examined. The residential sector and commercial sector accounted for approximately 27% and 23% of potential peak demand savings, respectively.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs, by Region and Customer Class (2018)

Region	Customer Class			
	Residential	Commercial	Industrial	All Classes
AK	5.0	13.0	9.0	27.0
FRCC	1,477.6	1,344.3	276.0	3,097.9
HI	14.1	20.3	0.0	34.4
MRO	1,937.8	1,121.4	2,193.3	5,252.7
NPCC	143.6	498.5	416.6	1,058.7
ReliabilityFirst	1,776.4	730.9	3,391.8	5,899.0
SERC	1,206.0	1,305.1	5,941.9	8,452.9
SPP RE	234.9	368.9	1,083.0	1,686.8
Texas RE	277.1	405.5	231.5	914.0
WECC	1,420.2	1,213.1	1,749.7	4,382.6
Unspecified	46.5	0.0	42.4	89.0
Total	**8,539.2**	**7,021.0**	**15,335.2**	**30,895.0**

Sources: EIA, EIA-861 Demand_Response_2018, and Utility_Data_2018 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 RTO/ISO wholesale demand response programs in 2018 and 2019.[42] From 2018 to 2019, demand resource participation in the wholesale markets increased by approximately 2,734 MW, or nine percent, to a total of 32,408 MW. On a regional basis, the largest absolute increases were reported in PJM, CAISO, and MISO with reported increases of 891 MW, 800 MW, and 681 MW, respectively. On a percentage basis, the highest increases from 2018 to 2019 were reported in CAISO and ISO-NE. Participation decreased in only one region, NYISO, where wholesale demand resource participation decreased by 27 MW, or 4.6%. For the first time since 2015, SPP reported registration of demand response assets in its markets, however, these assets totaled only 0.3 MW.

[42] 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).

Table 3-3: Demand Resource Participation in RTOs/ISOs (2018 & 2019)

RTO/ISO	2018		2019		Year-on-Year Change	
	Demand Resources (MW)	Percent of Peak Demand[15]	Demand Resources (MW)	Percent of Peak Demand[15]	MW	Percent
CAISO	2,400.0 [1]	5.2%	3,200.0 [2]	7.2%	800.0	33.3%
ERCOT	3,261.9 [3]	4.4%	3,551.8 [4]	4.8%	289.9	8.9%
ISO-NE	356.0 [5]	1.4%	454.8 [6]	1.9%	98.8	27.8%
MISO	12,931.0 [7]	10.6%	13,612.0 [8]	11.3%	681.0	5.3%
NYISO	1,431.1 [9]	4.5%	1,404.0 [10]	4.6%	-27.1	-1.9%
PJM	9,294.0 [11]	6.3%	10,185.0 [12]	6.9%	891.0	9.6%
SPP	0.0 [13]	0.0%	0.3 [14]	0.0%	0.3	-
Total	**29,674.0**	**6.0%**	**32,407.9**	**6.6%**	**2,733.9**	**9.2%**

Sources: [1] CAISO, *2018 Annual Report on Market Issues and Performance* (May 2019) at 42; [2] CAISO, *2019 Annual Report on Market Issues and Performance* (July 2020) at 52; [3] Estimated based on ERCOT, *2018 Annual Report of Demand Response in the ERCOT Region* (Mar. 2019) at 3 and Table 1; [4] Estimated based on ERCOT, *2019 Annual Report of Demand Response in the ERCOT Region* (Mar. 2020), Table 1 and Table 3; [5] ISO-NE, *Monthly Statistics Report*, presented at Demand Resources Working Group Meeting (Dec. 2018) at 4; [6] ISO-NE, *Monthly Statistics Report*, presented at Demand Resources Working Group Meeting (Dec. 2019) at 4; [7] Potomac Economics, *2018 State of the Market Report for the MISO Electricity Markets* (June 2019), Table 15 at 91; [8] Potomac Economics, *2019 State of the Market Report for the MISO Electricity Markets* (June 2020), Table 18 at 108; [9] NYISO, *2018 Annual Report on Demand Side Management Programs of the New York Independent System Operator, Inc.*, ER01-3001 (Jan. 2019), Attachment I, Table 1, at 7; [10] NYISO, *NYISO 2019 Annual Report on Demand Response Programs*, (Jan. 2020) Table 1 at 6; [11] PJM, *2018 Demand Response Operations Markets Activity Report* (Mar. 2019), at 3, 4. Figure represents "unique MW"; [12] PJM, 2019 Demand Response Operations Markets Activity Report (Apr. 2020) at 3, 4. Figure represents "unique MW"; [13] 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 (May 24, 2016), at 4; and SPP Response to Request for Additional Information, Docket No. ER12-1179-025 (Mar. 5, 2018), at 1–2, 4; [14] SPP, *2019 State of the Market Report* (May 2020) at 45; [15] Sources for peak demand data include: CAISO 2018 and 2019 Annual Reports on Market Issues and Performance; ERCOT 2018 & 2019 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report (July 2020); 2018 and 2019 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2018 and 2019; 2018 and 2019 PJM State of the Markets Reports, Vol. 2; SPP 2018 and 2019 State of the Market Reports.

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

CAISO realized a net increase of 800 MW within its demand response programs from 2018 to 2019. The 800 MW net increase is attributable to increased enrollments in the Proxy Demand Response program, which allows resources to bid economically in CAISO's day-ahead and real-time wholesale energy markets as supply. CAISO therefore experienced aggregate increases of approximately 1,000 MW in the Proxy Demand Response program, which was offset by a decrease of approximately 200 MW in the Reliability Demand Response Resource program.

For ISO-NE, 2019 was the second year of full integration of demand response into ISO-NE's price-responsive demand program, which dispatches demand response resources on the basis of their energy market offers. In 2019, 455 MW of Active Demand Capacity Resources were reported, an increase of almost 100 MW from 2018. This increase occurred during the second year of ISO-NE's Pay-for-Performance program, which places more stringent requirements on all resources, including demand response resources, that participate in ISO-NE's forward capacity market.

PJM reported an increase of 891 MW in demand resources from 2018 to 2019. An increase of 261 MW was reported in PJM's economic demand programs while an increase of 637 MW was reported in PJM's emergency energy-only demand response programs. As discussed below, for the 2020/2021 Delivery Year, all resources participating in PJM's capacity market must meet new performance requirements.

MISO reported a total demand response enrollment increase of 681 MW, or 11%, from 2018 to 2019. This increase is primarily due to an increase of 531 MW of Load Modifying Resources. This increase was slightly offset by a decrease in enrollment of 50 MW in MISO's Emergency Demand Response program.

Demand resource participation in ERCOT increased 290 MW, or nine percent, from 2018 to 2019 to a total of 3,552 MW. As in previous years, most of this growth is due to a 245 MW increase in resources participating in the Responsive Reserve Service (RRS),[43] through which demand-side resources can provide frequency response. From 2018 to 2019, an increase of 45 MW was reported in the Emergency Response Service programs[44] while an increase of 34 MW was reported in ERCOT's Fast Responding Regulation Service.[45]

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[43] 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 2018 and 2019; resources must be registered and qualified to offer into the market. While ERCOT reports that as much as 5,064 MW of resources were capable of participating in RRS as of the end of 2019—an increase of 442 MW from 2018—not all of these resources were actively participating in the market. *See* ERCOT, *2019 Annual Report of Demand Response in the ERCOT Region* (Mar. 2020), at 2-4.

[44] The ERS provides 10- and 30-minute load reduction services. Commission staff estimated ERS capacity by averaging the capacity procured for the eight 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).

[45] FRRS allows market participants using energy storage resources to participate as a Generation Resource when they inject energy onto the transmission grid and as a Controllable Load Resource (CLR) when they

NYISO demand response resource participation decreased by 27 MW, or two percent. This decrease is attributable to a decrease of 27 MW in Special Case Resources, which are demand-side resources that offer unforced capacity into NYISO's Installed Capacity Market. NYISO reports that enrollment of resources providing Operating Reserves in NYISO's economic Demand-Side Ancillary Services Program, in which loads offer into the day-ahead market as energy, remained at 116.5 MW.

In 2019, SPP reported 0.3 MW of demand response capability, the first demand response resources reported in SPP since January 2015. SPP demand response programs are controlled or dispatched load curtailment programs.[46]

COVID-19 Impacts on Demand Response

The COVID-19 pandemic has seriously impacted various segments of the United States' energy industry. On July 8-9, 2020, the Commission held a technical conference to consider the impacts on the United States' energy industry caused by the COVID-19 pandemic.[47] The two-day, Commissioner-led technical conference explored a wide range of topics affecting the electric, natural gas, and oil industries that the Commission regulates. At the technical conference, utilities and RTOs/ISOs described changes in electricity demand and load shapes and how these changes affected forecasts, planning and operations.[48]

The effects of the COVID-19 pandemic were reflected in lower overall demand for electricity in much of the United States in the first half of 2020 relative to previous years. For example, NERC examined the impacts of COVID-19, reporting that some areas of the country reported up to 15% decreases in peak demand.[49]

In order to limit the spread of COVID-19, businesses, schools, and other institutions in many states and localities closed or moved to full time telework; this affected load patterns and load shapes, which in turn impacted the availability of demand response resources. Generally, RTOs/ISOs noted short-term drops in overall electricity demand in the spring, with a return to historic peak demand levels from June through

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withdraw from the transmission grid. In 2019, there were six CLRs registered that provided an average of 35 MW in each hour—the maximum allowed under FRRS Protocols.

[46] SPP Tariff, Attachment AE, Section 1.1 – Definitions D.

[47] *See* FERC, *Impacts of COVID-19 on the Energy Industry*, Notice of Technical Conference, Docket No. AD20-17-000 (May 20, 2020).

[48] Consolidated Edison Company of New York, Comment, Docket No. AD20-17-000, at 2 (filed June 30, 2020); MISO, Comment, Docket No. AD20-17-000, at 2 (filed June 30, 2020); PJM, Comment, Docket No. AD20-17-000, at 5, 6 (filed July 1, 2020).

[49] NERC, *2020 Summer Reliability Assessment* (June 2020) at 5, 11, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.

September.[50] As a result of business closures, and other social distancing measures such as telework, for the first half of 2020, demand shifted from commercial and industrial users to residential users in various regions of the country.[51] For example, a preliminary analysis of residential customers in Austin, Texas, suggests that March 2020 residential demand was up 20% compared to March demand for the previous three years.[52]

Nevertheless, the pandemic's long-term impacts on demand and demand response programs are yet to be determined. As discussed in more detail in Chapter 5, because of the pandemic's effects on businesses, MISO filed a waiver that the Commission approved to allow Load Modifying Resources to enroll additional assets in order to fulfill their capacity obligations. Additionally, the New York Public Service Commission (NYPSC) issued an order granting requests from utilities for greater flexibility in demand response customer enrollment, modification to enrollment capability, and waiver of minimum performance requirements.[53] Finally, SPP delayed testing requirements for controllable and dispatchable demand response programs and behind-the-meter generation resources used to meet the Resource Adequacy Requirement from 2020 to 2021, as discussed in Chapter 4.

[50] *See* CAISO, *COVID-19 Impacts to California ISO Load & Markets: March 17 – July 26, 2020* (July 2020), http://www.caiso.com/Documents/COVID-19-Impacts-ISOLoadForecast-Presentation.pdf; ERCOT, *COVID-19 Load Impact Analysis* (Sep. 1, 2020), http://www.ercot.com/content/wcm/lists/200201/ERCOT_COVID-19_Analysis_Sept_1.pdf; MISO, *COVID-19 Impact to Load & Outage Coordination* (Aug. 2020), https://cdn.misoenergy.org/COVID%2019%20Impacts%20to%20MISO%20Load%20and%20Outage_as%20of%20August%2017469058.pptx; NYISO, *Estimated Impacts of COVID-19 on NYISO Load* (Sep. 2020), https://www.nyiso.com/documents/20142/15313556/02%20NYISO_COVID19%20Impacts.pdf/d10b26f0-4487-c1e1-febc-1bc8f56b01a9; SPP Market Monitoring Unit, *Spring 2020 Quarterly Report* (Aug. 2020), https://www.spp.org/documents/62709/spring%202020_quarterly_presentation.pdf.

[51] PJM, Comment, Docket No. AD20-17-000, at 6, 7 (filed July 1, 2020).

[52] Power Grid International, "COVID-19 is Changing Residential Electricity Demand" (Apr. 9, 2020), https://www.power-grid.com/2020/04/09/covid-19-is-changing-residential-electricity-demand/?utm_medium=email&utm_campaign=powergrid_weekly_newsletter&utm_source=enl&utm_content=2020-04-09.

[53] *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, Case No. 14-E-0423 (New York PSC May 14, 2020), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4DDBB423-1C1F-4C61-9D03-B4B042BEB4F9}.

Demand Response Deployments

While most regions of the country realized changes in load consumption patterns and overall electricity demand in 2020, demand response deployments continued to occur. Below are notable demand response events since the last report.[54]

From August 14 through 19, 2020, the western United States experienced temperatures 10-20 degrees above normal and California experienced four out of its five hottest August days since 1985.[55] To prepare for the heat wave, on August 12, 2020, for August 14 through August 17, 2020, and on August 17 for August 17 through August 21, 2020, CAISO declared Restricted Maintenance Operations requiring generators and transmission operators to postpone planned outages for routine equipment maintenance due to expected high loads and temperatures.[56] On August 13, 2020, CAISO forecast a possible system reserve deficiency and issued a Grid Alert Notice encouraging electricity conservation for the August 14 afternoon and evening peak.[57] On August 14 and 15, CAISO issued a Grid Alert, Grid Warning, and declared Stage 2 and Stage 3 Emergencies.[58] On August 18, CAISO issued a Grid Alert as well as a notice for 500 MW of firm load interruptions for each hour.[59]

Analysis from the CAISO Department of Market Monitoring (DMM) showed that, from August 14 to August 18, CAISO activated between 820 MW and 975 MW of Reliability Demand Response Resources during net peak load hours.[60] This equates to between 44% and 53% of the 1,847 MW of resource

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[54] Last year's report discussed demand response deployments in PJM in 2019. On October 2, 2019, PJM dispatched Capacity Performance Demand Resource Long Lead resources in the BGE, Dominion, and PEPCO zones during a Performance Assessment Interval. PJM reports that overall event performance during the mandatory compliance period was 78%. Capacity Performance by demand response resources varied by zone and ranged from 75% to 250%, according to PJM. This new information on the performance of demand response resources in PJM became available recently. *See* PJM, *Load Management Performance Report 2019/2020* (Aug. 2020) at 9-10, https://www.pjm.com/-/media/markets-ops/dsr/2019-2020-dsr-activity-report.ashx?la=en.

[55] CAISO, *Preliminary Root Cause Analysis, Mid-August 2020 Heat Storm*, (Oct. 2020), at 2, http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf (CAISO Preliminary Root Cause Analysis).

[56] CAISO, *AWE Grid History Report* (Sep. 9, 2020) at 4, 19, http://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf.

[57] *Id.* at 5.

[58] *Id.* at 7-14.

[59] *Id.* at 24.

[60] CAISO, *Report on System and Market Conditions, Issues and Performance: August and September 2020* (Nov. 24, 2020) at 59,

adequacy capacity from demand response programs in August.[61] The CAISO DMM stated that less than two thirds of the 1,847 MW of resource adequacy capacity[62] met by demand response was available for dispatch in real-time during load curtailment hours on August 14 and 15.[63] The CAISO DMM reported that approximately two-thirds of the 1,604 MW of resource adequacy utility demand response capacity was bid in or self-scheduled in the real-time market during hours 19 and 20 on August 14.[64] On August 15, this total descreased to 58% and 57% in hours 19 and 20, respectively.[65] Of the 243 MW of supply plan demand response capacity, 58% was bid in or self-scheduled in the real-time market during hours 19 and 20 on August 14, and, on August 15,[66] 41% of supply plan demand response capacity was bid in or self-scheduled.[67]

On average from August 14 through August 19, demand response resources in CAISO provided 67% of the total MWh of demand response that were dispatched.[68] Reliability Demand Response Resources, which comprise the majority of the available demand response capacity, provided 71% of the MWh of demand response that they were dispatched to provide between August 14 and August 19.[69] There are neither established performance metrics nor comparable historical data to evaluate this 71% figure for Reliability

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http://caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf (CAISO Report on System Conditions).

[61] *Id.* at 55.

[62] *Id.* at 55. According to CAISO, this resource adequacy capacity "was comprised of both utility demand response programs which are credited against resource adequacy requirements across all local regulatory authorities, and third-party demand response programs which are contracted with load serving entities and shown on resource adequacy supply plans."

[63] *Id.* at 5.

[64] *Id.* at 27.

[65] *Id.*

[66] *Id.* at 58. The CAISO DMM stated that some utility demand response programs are unavailable on weekends and holidays, which accounted for the drop in utility demand response capacity available on August 15.

[67] *Id.* at 27. For comparison, 92%-95% of total gas-fired resource adequacy capacity was bid in or self-scheduled during these hours.

[68] FERC, *Preliminary Observations on the August 2020 California Heat Storm*, Docket No. AD21-3-000, at 15 (Dec. 17, 2020), https://cms.ferc.gov/sites/default/files/2020-12/California%20Heat%20Storm%20Inquiry%20Presentation%2C%20December%2017%2C%202020%20--%20Script.pdf.

[69] *Id.*

Demand Response Resources. Over the same period, Proxy Demand Resources provided 50% of the demand response that they were dispatched to provide.[70] Comparison of Proxy Demand Resource performance is similarly difficult because, while Proxy Demand Resources have been regularly dispatched, performance varies dramatically. The CAISO Department of Market Monitoring has not yet fully evaluated the performance of demand response resources that were dispatched.[71]

CAISO reported other demand reductions. The California Energy Commission coordinated with the U.S. Navy and Marine Corps to reduce load by 23.5 MW through ships' disconnect from shore power, back up generation, and microgrids.[72] The California Energy Commission also coordinated with six other microgrids to reduce load by 1.2 MW each day.[73] The California Department of Water and Power and the U.S. Bureau of Reclamation shifted 72 MW of on-peak pumping load.[74] The Governor's Office contacted industrial customers to shift loads from peak hours, reducing loads by a combined 162.3 MW.[75] Finally, on August 17, the CPUC issued a letter allowing back-up generators in connection with demand response programs to be used, resulting in 50 MW of demand reduction.[76]

In ERCOT, peak demand levels in 2020 were slightly below record demand levels in 2019.[77] However, in 2020, ERCOT deployed RRS multiple times in each of June, July, August, and September.[78] Some deployments of RRS coincided with a DC Tie Outage and advisories that physical responsive capability was less than 3,000 MW.

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[70] *Id.* at 16.

[71] CAISO, *Report on System and Market Conditions, Issues, and Performance: August and September 2020* (Nov. 24, 2020) at 3, http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf.

[72] CAISO Preliminary Root Cause Analysis at 61.

[73] *Id.*

[74] *Id.*

[75] *Id.* at 62. The industrial customers include California Resources Corporation, California Steel Industries, Dole Foods, and Poseidon Water Desal Plant.

[76] *Id.* at 61.

[77] POWER Magazine, "Summer 2020 Brought ERCOT Market Challenges, But Nothing Like 2019" (Sep. 18, 2020), https://www.powermag.com/summer-2020-brought-ercot-market-challenges-but-nothing-like-2019/.

[78] ERCOT, "Operations Messages," http://www.ercot.com/services/comm/mkt_notices/opsmessages. *See also supra* n.43.

NYISO operates the reliability-based Targeted Demand Response Program to deploy wholesale market Emergency Demand Response Program resources and Special Case Resources (SCR) on a voluntary basis to solve local reliability needs.[79] In July 2020, NYISO activated the Targeted Demand Response Program,[80] deploying Emergency Demand Response Program resources and SCRs on five separate days in Zone J, which consists of New York City, during the afternoon and evening peak.[81] In addition, retail demand response programs were activated in June through August 2020 by seven different transmission owners.[82]

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[79] NYISO, *2019 Annual Report on Demand Response Programs* (Jan. 2020) at 2, https://www.nyiso.com/documents/20142/10360921/NYISO-2019-Annual-Report-on-Demand-Response-Programs.pdf/25a998b4-d134-f5f5-2a27-a17568e9b3c7.

[80] NYISO, *Historic EDRP and SCR Activation Information* (July 2020) at 5, https://www.nyiso.com/documents/20142/1401632/EXT-DR-Events-and-Tests-History-With-CPs-Thru-08-27-2020.pdf/ecc61e6a-3f05-763a-45cf-789fbceb3b7e; NYISO, *NYISO 2020 Hot Weather Operations* (Sep. 2020) at 27, https://www.nyiso.com/documents/20142/15417436/04%20Summer%202020%20Hot%20Weather%20Operating%20Conditions.pdf/b31c0a7e-7d44-d46e-78a6-9dcf858c29af.

[81] S&P Global Platts, "Heat boosts US Mid-Atlantic power demand; prices remain moderate," (July 20, 2020), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/072020-heat-boosts-us-mid-atlantic-power-demand-prices-remain-moderate.

[82] NYISO, *NYISO 2020 Hot Weather Operations* (Sep. 2020) at 26, https://www.nyiso.com/documents/20142/15417436/04%20Summer%202020%20Hot%20Weather%20Operating%20Conditions.pdf/b31c0a7e-7d44-d46e-78a6-9dcf858c29af.

4. Potential for Demand Response as a Quantifiable, Reliable Resource for Regional Planning Purposes

In its recent 2020 State of Reliability report, NERC assessed the changing resource mix and the role demand response played in regional planning as well as operations. NERC observed that the resource mix continued to evolve as conventional large-scale generation is replaced by natural gas, wind, solar photovoltaic, and battery storage, as well as other emerging distributed technologies.[83] According to NERC, higher penetration of variable generation resources created a growing need for flexible resources like demand response to balance electricity supply and demand, ensure resource adequacy, and meet ramping needs.[84] NERC stated that planners and operators could face challenges when integrating variable generation resources and other emerging technologies as inputs, potentially requiring revisions to operational practices, enhancement of NERC Reliability Standards, and changes in market designs.[85] NERC also considered projected demand, resource capacity, transmission projects, as well as dispatchable and controllable demand response resources to provide a 10-year reliability focused assessment of the bulk power system.[86]

NERC notes that RTOs/ISOs currently use demand response resources for regional planning purposes and that expected demand reductions from dispatchable and controllable demand response programs can yield forecasted results if called upon.[87] For example, ERCOT has operational tools available, including calling on demand response resources that can provide ancillary services, to maintain system reliability.[88] In addition, in June 2018, ISO-NE integrated dispatchable, price-responsive demand resources into its energy and reserve markets. These resources are used in calculating ISO-NE's installed capacity and availability of the demand resources is based on historical performance.[89] Further, MISO has two categories of demand

[83] NERC, *2020 State of Reliability* (July 2020) at 45, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2020.pdf.

[84] *Id.* at 49.

[85] *Id.* at 45.

[86] NERC, *2019 Long-Term Reliability Assessment* (Dec. 2019), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf.

[87] *Id.* at 5.

[88] *Id.* at 13.

[89] *Id.* at 63.

response resources, direct control load management and interruptible load, that it uses for demand-side management.[90]

Other RTOs/ISOs use demand response for regional planning purposes. For example, the PJM capacity market procures enough resources to meet projected peak demand plus a reserve margin. Beginning June 1, 2020 for the 2020/2021 delivery year and subsequent delivery years, only resources that meet new Capacity Performance requirements will be used to meet reliability and resource adequacy needs through the capacity market.[91] Seasonal resources, such as summer demand response resources, can pair with winter period capacity resources and continue to participate in the PJM capacity market.

[90] *Id.* at 51.

[91] PJM Manual 18, *PJM Capacity Market* (May 2020) at 20, https://www.pjm.com/~/media/documents/manuals/m18.ashx.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter provides information on retail (incentive-based) demand response[92] and dynamic pricing[93] programs in 2018 and 2019, and summarizes recent actions related to demand response taken at the federal, regional, and state levels, as well as by industry. Since 2013, nationwide enrollment in dynamic pricing programs has increased by over 3.2 million customers, or 54%, while enrollment in incentive-based demand response programs has increased by 565,000 customers, or six percent. In 2018, enrollment in retail demand response programs and dynamic pricing programs eclipsed nine million customers in each category for the first time. The broad trend of sizeable annual increases in dynamic pricing program participation may signal that utilities in certain regions are focusing on increasing enrollment in dynamic pricing programs in order to leverage their advanced meter investments.

Enrollment in Retail Demand Response and Dynamic Pricing Programs

As shown in Table 5-1 and Figure 5-1 below, from 2017 to 2018 the number of retail customers enrolled in (incentive-based) retail demand response programs nationwide increased by 311,300 customers, or three percent, to over 9.7 million customers. Changes in customer enrollment in retail demand response programs varied by NERC region, as seen in Table 5-1.

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[92] Demand-side management (DSM) programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. 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-861S Instructions, Schedule 6 Part B, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; 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), https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response.pdf.

[93] Dynamic pricing programs, also known as time-based rate programs, are designed to modify patterns of electricity usage, including the timing and level of electricity demand. This includes time of use prices as well as real time pricing, variable peak pricing, critical peak pricing, and critical peak rebate programs. *See* EIA, 2018 Form EIA-861S Instructions, Schedule 6 Part C, https://www.eia.gov/electricity/data/eia861/.

Table 5-1: Customer Enrollment in Retail Demand Response Programs by Region (2017 & 2018)

Region	Enrollment in Retail Demand Response Programs		Year-on-Year Change	
	2017	2018	Customers	Percent
AK	2,414	2,400	-14	-0.6%
FRCC	1,214,003	1,176,964	-37,039	-3.1%
HI	34,055	33,831	-224	-0.7%
MRO	1,239,050	1,241,834	2,784	0.2%
NPCC	63,155	110,315	47,160	74.7%
ReliabilityFirst	2,267,920	2,562,583	294,663	13.0%
SERC	1,173,951	1,084,715	-89,236	-7.6%
SPP RE	312,461	294,786	-17,675	-5.7%
Texas RE	352,072	280,640	-71,432	-20.3%
WECC	2,778,440	2,960,288	181,848	6.5%
Unspecified	3,417	3,882	465	13.6%
Total	**9,440,938**	**9,752,238**	**311,300**	**3.3%**

Sources: EIA, EIA-861 Demand_Response_2017, Utility_Data_2017, Demand_Response_2018, and Utility_Data_2018 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.

The growth in customer enrollment in retail demand response programs from 2017 to 2018 is concentrated in four regions; MRO, NPCC, ReliabilityFirst, and WECC. The large increase in customer enrollment in NPCC, approximately 75% annual growth, is primarily attributable to an enrollment increase of over 42,000 customers reported by Consolidated Edison Company in New York. In ReliabilityFirst, utilities reported an increase of almost 295,000 customers, or 13%, from 2017 to 2018 due to large customer enrollment increases reported by Consumers Energy, Duke Energy Ohio, and Metropolitan Edison, as well as other utilities. In WECC, the over 181,000 increase from 2017 to 2018 is due primarily to customer enrollment increases reported by Pacific Gas & Electric and Arizona Public Service.

Conversely, annual decreases in customer enrollment in retail demand response programs were reported in four NERC regions, as well as Alaska and Hawaii. The largest absolute and percentage decreases were reported in SERC and Texas RE. In SERC, where the total reported decrease was approximately 89,000 customers, decreases were reported by City of Columbia Missouri, Duke Energy Carolinas, and Louisville Gas & Electric, among others. In Texas RE, the largest decreases were reported by Austin Energy and the City of San Antonio. However, utilities in many regions reported increases that partially offset regional decreases. Annual changes in customer enrollment in retail demand response programs by NERC region since 2013 are shown in Figure 5-1 below. Regionally, WECC and ReliabilityFirst continue to report the highest customer enrollment, with the increase from 2017 to 2018 in ReliabilityFirst bringing the region to its highest ever reported annual enrollment.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by Region (2013–2018)

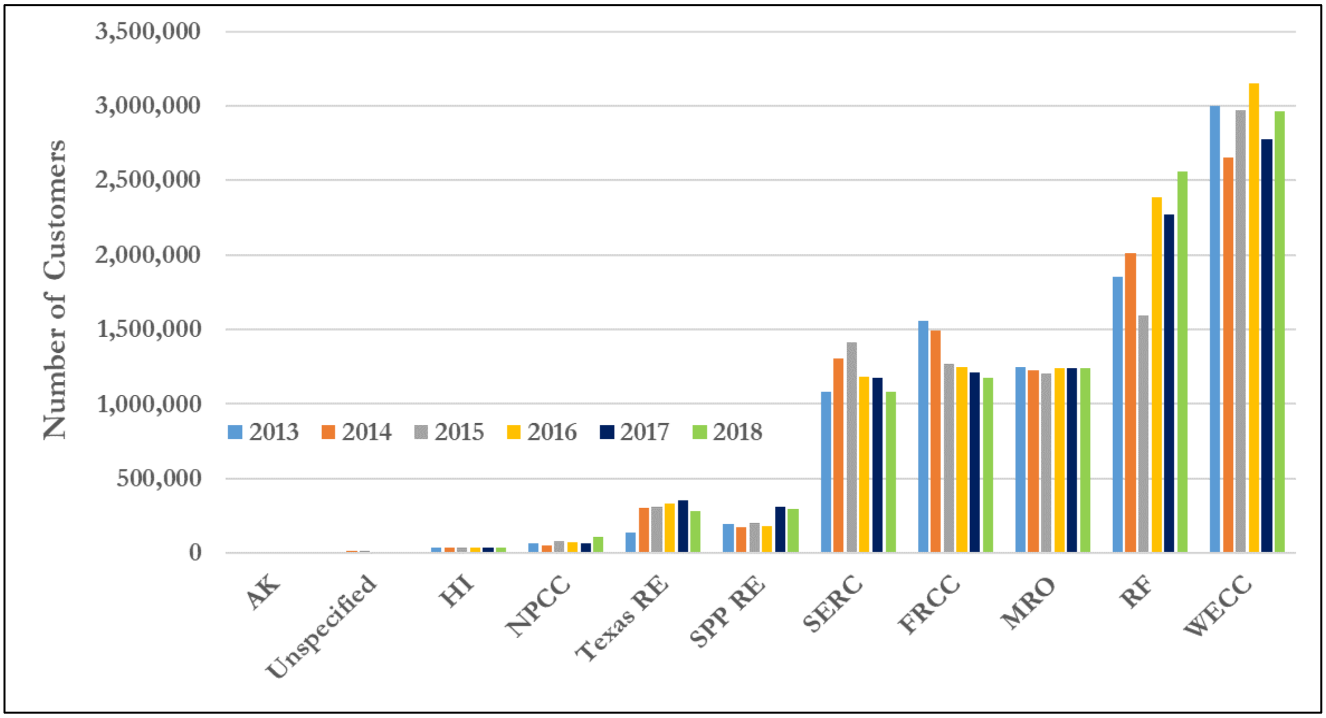


Table 5-2 and Figure 5-2 below present changes in customer enrollment in retail dynamic pricing programs by NERC region. As seen in Table 5-2 below, over 9.2 million customers were enrolled in retail dynamic price programs in the United States in 2018. Between 2017 to 2018, over 722,000 new customers were enrolled in retail dynamic pricing programs, resulting in an eight percent increase. From 2017 to 2018, all regions except for SPP RE reported increases in customer enrollment in retail dynamic pricing programs. In 2018, WECC and ReliabilityFirst each reported a total of over 3 million customers enrolled in retail dynamic price programs. Approximately 39% of all customers enrolled in retail dynamic price programs in 2018 were located in the WECC region while approximately 36% were located in ReliabilityFirst. Additionally, approximately 13% of all customers enrolled in retail dynamic price programs nationwide were enrolled in programs run by utilities in SPP RE.

Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Region (2017 & 2018)

Region	Enrollment in Dynamic Pricing Programs		Year-on-Year Change	
	2017	2018	Customers	%
AK	45	47	2	4.4%
FRCC	28,720	32,557	3,837	13.4%
HI	2,665	2,688	23	0.9%
MRO	166,283	166,305	22	0.0%
NPCC	258,669	298,973	40,304	15.6%
ReliabilityFirst	3,241,696	3,332,498	90,802	2.8%
SERC	243,222	323,823	80,601	33.1%
SPP RE	1,218,448	1,216,379	-2,069	-0.2%
Texas RE	4,404	19,147	14,743	334.8%
WECC	3,155,860	3,590,632	434,772	13.8%
Unspecified	177,708	236,820	59,112	33.3%
Total	**8,497,720**	**9,219,869**	**722,149**	**8.5%**

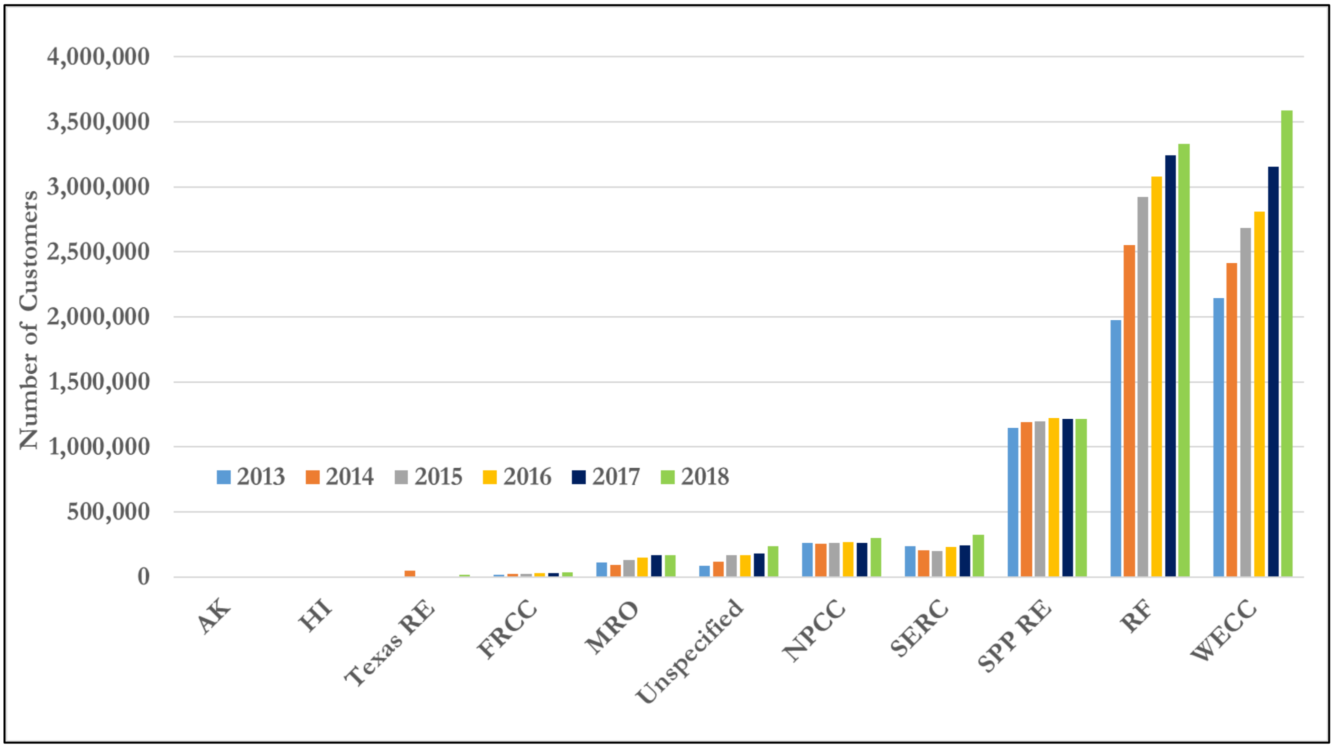
Sources: EIA, EIA-861 Dynamic_Pricing _2017, Utility_Data_2017, Dynamic_Pricing_2018, and Dynamic_Pricing_2018 data files.

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.

Large increases were also reported in NPCC, ReliabilityFirst, SERC, and WECC. In NPCC, large increases were reported by Consolidated Edison, Long Island Power Authority, and New York State Electric and Gas Corp. In ReliabilityFirst, Commonwealth Edison and Baltimore Gas & Electric (BG&E) reported increases of approximately 43,000 customers and 20,000 customers. The largest increase in SERC was reported by Ameren Illinois, with over 63,000 new customers enrolled in dynamic pricing programs. Finally, from 2017 to 2018 in WECC, Pacific Gas & Electric reported an increase of almost 159,000 customers while Southern California Edison Company (SCE) reported an increase of over 49,000 customers.

Figure 5-2 below shows changes in customer enrollment in dynamic pricing programs from 2013 to 2018 by NERC region. WECC and ReliabilityFirst continue to report the highest number of customers enrolled in dynamic pricing programs. From 2014 to 2017, ReliabilityFirst has reported the highest number of customers enrolled in dynamic pricing programs. However, in 2018, WECC reported the highest number of customers enrolled, with approximately 3.6 million customers, followed by 3.3 million in ReliabilityFirst.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Region (2013–2018)



FERC Demand Response Orders and Activities

Participation of Distributed Energy Resource Aggregations in Markets Operated by RTOs and ISOs (Order No. 2222)

On September 17, 2020, the Commission issued Order No. 2222, revising the Commission's regulations to remove barriers to the participation of distributed energy resource (DER) aggregations in the capacity, energy, and ancillary services markets operated by RTOs and ISOs.[94] Order No. 2222 defines a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter" and defines a DER aggregator as "the entity that aggregates one or more [DERs] for purposes of participation in the capacity, energy and/or ancillary services markets of the [RTOs/ISOs]." These DERs may include, but are not limited to, resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.

Order No. 2222 finds that existing RTO/ISO market rules are unjust and unreasonable with regard to participation of DER aggregations in the RTO/ISO markets and requires each RTO/ISO to:

[94] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020).

- develop tariff provisions that ensure that its market rules facilitate the participation of DER aggregations;
- allow DER aggregations to participate directly in RTO/ISO markets; and,
- establish DER aggregators as a type of market participant that can register DER aggregations under one or more participation models that accommodate their physical and operational characteristics.

The Order requires that RTOs/ISOs implement tariff provisions to address various technical and operational issues, including minimum size of DER aggregations, maximum DER size for participation in DER aggregations, locational requirements, bidding parameters, metering and telemetry, and coordination between relevant parties and authorities. Order No. 2222 does not adopt on opt-out mechanism with respect to DER Aggregations similar to that adopted in Order No. 719 with respect to demand response. However, Order No. 2222 does not alter that Order No. 719 opt-out with respect to demand response. The Order also includes an opt-in mechanism for small utilities, similar to the opt-in provided in Order No. 719-A with respect to demand response. Rehearing of Order No. 2222 is pending before the Commission.

NYISO Special Case Resource Buyer-Side Mitigation (Docket No. EL16-92-001, EL16-92-003, ER17-996-002, and ER17-996-003)

In a February 2020 order, the Commission found that NYISO's offer floors for SCR resources in the capacity market should include only the incremental costs of providing wholesale-level capacity services and that payments from retail-level demand response programs designed to address distribution-level reliability needs are not properly considered to be received "for providing Installed Capacity," and therefore should be excluded from the calculation of SCRs' offer floors.[95] In a related proceeding, in September 2020, the Commission found that the payments received under the Distribution Load Relief Programs operated by utilities qualify for exclusion from the calculation of SCR offer floors, but that payments received under the Commercial System Distribution Load Relief Programs do not qualify for exclusion from the calculation of SCR offer floors. In an October 2020 order, the Commission found that, pursuant to the standard set in the February 2020 Order, payments received under the Commercial System distribution Load Relief Programs were designed, in part, to offset transmission investment and not solely for distribution-level reliability needs. Therefore, the Commission found that payments received under the Commercial System distribution Load Relief Programs cannot be excluded from the calculation of offer floors for new SCRs under NYISO's buyer-side mitigation rules.[96]

PJM Price Responsive Demand (Docket Nos. ER20-271-000, ER20-271-001)

On December 30, 2019, the Commission accepted PJM's proposed revisions to update certain rules and requirements for Price Responsive Demand to conform with PJM's capacity market.[97] PJM's Price

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[95] *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,137 (2017), *order on reh'g*, 170 FERC ¶ 61,120 (2020) (February 2020 Order).

[96] *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,022 (2020).

[97] *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,252 (2019). PJM's compliance filing clarified that Price Responsive Demand is not eligible to receive bonus performance payments during a Performance

Responsive Demand program allows Load Serving Entities (LSEs) to designate part of their load as price-responsive in order to reduce energy and capacity charges, so long as the Price Responsive Demand load is under a dynamic retail rate structure, employs advanced metering, and uses supervisory controls to ensure that the committed Price Responsive Demand for demand reduction can be accomplished.[98] Under the Price Responsive Demand program, retail customers reduce load based on their individual Price Responsive Demand Curve with set price and quantity pairs that reflect their willingness to reduce load. However, because Price Responsive Demand is price-sensitive demand, LSEs do not receive energy payments but instead receive compensation in the form of lower energy bills. LSEs also earn capacity credits for Price Responsive Demand in their delivery area equal to their avoided capacity market costs.

On February 7, 2019, PJM filed a proposal to align the rules and requirements for Price Responsive Demand with the rules and requirements for resources that participate in the capacity market.[99] The Nominal Price Responsive Demand Value is the amount of MW a Price Responsive Demand Provider commits to reduce during the PJM annual peak. The Commission rejected the February 2019 filing and found that PJM's proposal to calculate the Nominal Price Responsive Demand Value as the lesser of the summer and winter load reductions did not conform with how PJM calculates an LSE's capacity obligation that is based on an LSE's demand during the PJM annual peak.[100] In the June 27 Order, the Commission found that PJM's proposal did not fully value load reductions during the annual peak and therefore would limit the amount of Price Responsive Demand that can be committed.[101] On October 31, 2019, to address the Commission's concerns in the February filing, PJM filed a new proposal to better represent the demand level that Price Responsive Demand is expected to reduce by during a Maximum Generation Emergency.[102] The Commission accepted these revisions in the December 2019 Order.

PJM Peak Shaving (Docket No. ER19-511-000, ER19-511-001, ER19-511-002)

On May 3, 2019, the Commission accepted PJM's proposal to reflect load reductions from summer Demand Response Resources (Summer Demand Resources) in load forecasts for an LSE's capacity requirements.[103] Summer Demand Resources that submit a Peak Shaving Adjustment Plan will be called on

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Assessment Interval when the Price Responsive Demand Curve has a price point above the real-time price during a Performance Assessment Interval. The filing was accepted by Delegated Letter Order on Feb. 28, 2020.

[98] *Id.* P 3.

[99] PJM, Filing, Docket No. ER19-1012-000 (filed Feb. 7, 2019).

[100] *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,268, at PP 22-25 (2019) (June 27 Order).

[101] *Id.* P 22.

[102] PJM, Filing, Docket No. ER20-271-000 (filed Oct. 31, 2019).

[103] *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,114 (2019). In the order, the Commission conditionally accepted PJM's filing, directing PJM to submit a compliance filing incorporating provisions in its Manual 19

to reduce consumption when pre-established parameters submitted as part of the plan are met. Summer Demand Resources will be expected to reduce load without any communication from PJM dispatch, and PJM will compare the Summer Demand Resource's claimed MW value in its plan against the resource's actual performance using a customer baseline load methodology. After three years of peak shaving, PJM's load forecast adjustment values will be determined entirely by the Summer Demand Resource's actual average rolling three-year performance.

For Summer Demand Resources to participate in the peak shaving program, resources must be governed by a tariff or order adopted by a Relevant Electric Retail Regulatory Authority (RERRA), e.g., a state public utility commission, municipal utility council, or cooperative utility governing board. In the filing, PJM stated that the RERRA requirement ensures that peak shaving programs in PJM's load forecast do not usurp state authority or impede states from taking actions within their authority. PJM also stated that this requirement provides greater certainty because resources governed by a RERRA are likely to exist for several years, preventing fluctuating load forecasts and annual changes to the PJM capacity market's Variable Resource Requirement curve.[104] Further, resources participating in the peak shaving program are prohibited from participating in other PJM markets to prevent double counting of MW reductions from resources enrolled in the program.

MISO Load Modifying Resource Accreditation (Docket No. ER20-1846-000)

On August 14, 2020, the Commission accepted MISO's filing regarding capacity accreditation of demand resources and behind-the-meter-generation for participation in MISO's Planning Resource Auction based on a resource's notification time requirement and number of allowable calls.[105] The tariff previously allowed resources with a capacity obligation a maximum notification time of 12 hours to respond to a call for demand response. MISO stated that, previously, long-lead time Load Modifying Resources (LMRs) allowed MISO to pre-position resources for deployment before actual system emergencies. However, as the number of demand resources that cleared the capacity market increased, MISO observed a disparity between resources that cleared and resources that responded to calls for deployment. MISO implemented a two-year phase-out of capacity accreditation for LMRs with a notification time requirement greater than six hours. Beginning with the 2022/2023 planning year, MISO will accredit LMRs at 50% of their total capacity if they have a lead time greater than six hours but less than 12 hours and have a minimum of 10 allowable calls. LMRs with a lead time between six and 12 hours that are available for less than 10 call cannot receive a capacity credit. Beginning with the 2022/2023 planning year, demand resources with a notification time of six hours or less and between five and nine allowable calls will be accredited at 80%, while demand resources with a notification time of six hours or less and a minimum of 10 allowable calls

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pertaining to the peak shaving adjustment in the tariff. On June 26, 2019, in Docket No. ER19-511-002, the Commission issued a Letter Order accepting PJM's compliance filing.

[104] *Id.* PP 6, 10.

[105] *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,138 (2020).

will be accredited at 100%. For 2023/2024 planning year and beyond, LMRs with a lead time greater than six hours cannot receive capacity credit as a capacity resource.

MISO Waiver for Load Modifying Resources (Docket No. ER20-2156-000)

On July 16, 2020, the Commission granted MISO's waiver requesting that market participants be allowed to replace and/or supplement LMR assets that cleared the capacity market with newly registered LMR assets because of the effects of COVID-19 on some businesses.[106] Effective from July 15, 2020 through October 13, 2020, the waiver allows market participants whose LMRs that cleared the 2020/2021 capacity market to register new LMR assets to replace and/or supplement existing LMR assets. In order to be able to register new LMR assets, market participants with LMRs that cleared the capacity market must provide notarized attestation that their existing LMR assets are unable to perform up to their full accredited capacity as a result of the COVID-19 pandemic.

CAISO Tariff Amendment to Implement Demand Response Enhancements (Docket No. ER20-2443-000)

On October 1, 2020, the Commission approved CAISO's tariff revisions to enhance demand response participation in CAISO's wholesale markets.[107] The tariff revisions were developed during the third phase of CAISO's energy storage and distributed energy resource stakeholder initiative.[108] The revisions allow resources participating in the wholesale market as proxy demand resources to sub-meter electric vehicle supply equipment and measure performance separate from the retail account of the host facility. In the filing, CAISO noted that its previous limitations on sub-metering were "problematic for some customers because the [electric vehicle supply equipment] and the onsite host load may have very different load profiles and responses to CAISO dispatch."[109] CAISO also created a new demand response participation model that incentivizes behind-the-meter energy storage resources to "load shift" and increase consumption during oversupply conditions and return that energy to the system during periods of higher demand.[110]

SPP Tariff Revisions to Define Requirements for Demand Response Programs and Behind-The-Meter Generation for Resource Adequacy (Docket No. ER20-2578-000)

On September 23, 2020, the Commission issued a Delegated Letter Order accepting SPP's revisions to define requirements for demand response programs and behind-the-meter generation for resource adequacy

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[106] *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,069, at P 18 (2020).

[107] *California ISO,* 172 FERC ¶ 61,298 (2020).

[108] CAISO, Filing, Docket No. ER20-2443-000, at 5 (filed July 16, 2020).

[109] *Id.*

[110] *Id.* at 1-2.

purposes.[111] SPP distinguishes between dispatchable and non-dispatchable behind-the-meter generation and demand response. For resource adequacy in SPP, controllable and dispatchable demand response programs are treated as a reduction to the reported peak demand of a Load Responsible Entity while behind-the-meter generation is considered a resource capable of providing capacity to meet the resource adequacy requirement.[112]

Other Federal Demand Response Activities

Department of Defense

The U.S. Department of Defense (DoD) Defense Logistics Agency Energy (DLA Energy) provides the DoD and other federal government agencies with comprehensive energy solutions,[113] including administering incentive-based demand response programs. In fiscal year 2019, DLA Energy coordinated and facilitated the participation of 43 installations in demand response programs in 11 states and the District of Columbia—all of which are within organized wholesale markets—and had 73 MW of demand response enrolled in its programs.[114] DLA Energy reported savings of over $1.3 million in fiscal year 2019, with cumulative savings since 2008 totaling over $37 million.

General Services Administration

The General Services Administration (GSA) manages centralized procurement for the Federal government, which includes providing energy services for agency workspaces in buildings that are either federally owned or leased.[115] In December 2019, the GSA's Green Building Advisory Committee released its proposed roadmap and advice letter, stating that one of its primary objectives is to review and modify federal energy policy goals, which currently focus on energy reduction, to include load management, demand reduction, flexible rate structures, and exploration of pilot programs to better incorporate demand savings.[116] The

[111] *Sw. Power Pool, Inc.*, Docket No. ER20-2578-000, (Sep. 23, 2020) (delegated order).

[112] Sw. Power Pool, Inc., Filing, Docket No. ER20-2578-000, at 5 (filed July 31, 2020). *See* SPP Tariff, FERC FPA Electric Tariff, Open Access Transmission Tariff, Sixth Revised Volume No. 1, Attachment AA Section 2, Attachment AA Section 2, 1.0.0, Attachment AA Section 7, Attachment AA Section 7, 2.0.0, Attachment AA Section 10, Attachment AA Section 10, 1.0.0.

[113] DoD, *Defense Logistics Agency Energy, Fiscal Year 2019 Fact Book* (Jan. 2020) at 2, https://www.dla.mil/Portals/104/Documents/Energy/Publications/FactBookFiscalYear2019_lowres.pdf?ver=2020-01-21-104015-803.

[114] *Id.* at 57.

[115] GSA, "Background and History," https://www.gsa.gov/about-us/background-and-history.

[116] GSA, "GSA Green Building Advisory Committee Federal Building & Grid Integration: Proposed Roadmap Advice Letter" (Dec. 2019) at 10,

proposed roadmap discusses: partnering with utilities and RTOs/ISOs to conduct rate analyses; installing infrastructure in buildings for load management; evaluating the opportunity for federal agencies to participate in energy, ancillary services, and capacity markets; and identifying automated demand response technologies and grid-connected appliances that can respond to grid signals.[117]

Developments and Issues in Demand Response

State Legislative and Regulatory Activity Related to Demand Response and Dynamic Pricing

Electric utilities continue to implement time-based rates and develop more dynamic pricing offerings, in part, in response to customer feedback, an expansion of customer-sited distributed energy resources, and state directives. Smart grid technologies and distributed energy resources can improve reliability, efficiency, and flexibility, and state policymakers are considering updated rate designs to provide fair valuation for these new technologies while balancing utility and customer interests.[118] Further, state regulators and electric utilities have given particular attention to rate design for retail customers with electric vehicles in an effort to limit peak load growth and mitigate operational challenges at the distribution level from these electric vehicles.

- **Arizona.** On August 18, 2017, the Arizona Corporation Commission (ACC) authorized Arizona Public Service Company (APS) to transition their customers to a new set of modernized rate plans that incorporated time-varying rates and demand charges.[119] After receiving complaints from customers expressing concerns about rate increases and a lack of understanding of the new rate designs, the ACC directed ACC staff to investigate the effectiveness of APS' customer education and outreach program. On June 5, 2019, ACC staff filed a report that advised that APS' outreach plan should have included more personalized customer contact and the program did not convey

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https://www.gsa.gov/cdnstatic/Bldg%20Grid%20Integration%20Advice%20Letter%20Phase%20II%2012-9-19.pdf.

[117] *Id.* at 16, 18.

[118] National Conference of State Legislatures, Task Force on Energy Supply, *Modernizing the Electric Grid: State Role and Policy Options* (Nov. 2019) at 37, https://www.ncsl.org/Portals/1/Documents/energy/Modernizing-the-Electri-Grid_112519_34226.pdf.

[119] *See 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*, Decision No. 76295, Docket No. E-01345A-16-0036, (ACC Aug. 18, 2017), https://docket.images.azcc.gov/0000182160.pdf.

certain important information such as how behavioral changes in energy use impacts customers' bills under time-varying rates.[120]

- **California.** California continues to transition all residential customers to default time-of-use rates. The CPUC authorized San Diego Gas & Electric Company to begin transitioning residential customers to default time-of-use rates in March 2019, and authorized PG&E and SCE to begin transitioning residential customers to default time-of-use rates in October 2020.[121] On April 4, 2020, the CPUC authorized an additional ratepayer expenditure of up to $13.3 million to continue work on a statewide marketing, education, and outreach program to inform PG&E and SCE residential customers how the transition to default time-of-use rates would affect them.[122]

- **Colorado.** Following the July 2019 completion of a residential time-of-use pilot for residential customers with advanced meters,[123] PSCo filed a proposal with the Colorado Public Utilities Commission (Colorado PUC) to add default time-of-use rates for all residential customers with advanced meters.[124] PSCo's time-of-use program would only apply to the summer months starting in 2021, using an on-peak, off-peak pricing scheme.

- **District of Columbia.** On January 24, 2020, the District of Columbia Public Service Commission (DC PSC) issued an order reconvening a rate design working group and directed the Potomac

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[120] *In The Matter Of The Rate Review And Examination Of The Books And Records Of Arizona Public Service Company And Its Affiliates, Subsidiaries And Pinnacle West Capital Corporation*, Docket No. E-1345A-19-0003 (ACC June 5, 2019), https://docket.images.azcc.gov/0000198445.pdf.

[121] *See Application of Pacific Gas and Electric Company for Approval of its Residential Rate Design Window Proposals, including to implement a Residential Default Time-Of-Use Rate along with a Menu of Residential Rate Options, followed by addition of a Fixed Charge Component to Residential Rates (U39E)*, Docket Nos. A.17-12-011/A. 17-12-012/A. 17-12-013 (CPUC May 17, 2018), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M214/K512/214512974.PDF.

[122] *See Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, Docket No. R-12-06-013 (CPUC Apr. 2, 2020), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K373/331373874.PDF.

[123] *Review of Residential TOU Trial*, Docket No. 17M-0204E (Colorado PUC Nov. 27, 2019), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=916915&p_session_id=.

[124] *In the Matter of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado PUC No. 8-Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes*, Docket No. 19AL-0687E (Colorado PUC Dec. 2, 2019), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=917119&p_session_id=.

Electric Power Company (Pepco) to prepare a pilot residential time-of-use rate proposal.[125] Pepco subsequently submitted a residential time-of-use pilot program on March 9, 2020,[126] and then submitted a dynamic pricing proposal on April 23, 2020 to be used as a "strawman" for rate design working group discussions.[127] The rate design working group held its first meeting on May 12, 2020 to discuss Pepco's proposals.[128]

On January 31, 2020, the DC PSC approved Pepco's residential time-of-use rates designed for electric vehicle owners.[129] The offered rates include a lower whole-house rate if residential electric vehicle owners shift their charging to off-peak hours, and Pepco's implementation plan includes the deployment of a public charging infrastructure program.[130]

- **Hawaii.** On September 24, 2019, the Hawaii Public Utilities Commission (Hawaii PUC) issued an order opening a new proceeding to comprehensively investigate demand response and distributed

[125] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Formal Case No. 1130 (DC PSC Jan. 24, 2020), https://edocket.dcpsc.org/apis/api/filing/download?attachId=100684&guidFileName=f9794777-ad3d-4f71-bda1-ba04f95db4ad.pdf.

[126] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Pepco Residential Time-of-Use Pilot Proposal, Formal Case No. 1130 (DC PSC Mar. 9, 2020), https://edocket.dcpsc.org/apis/api/filing/download?attachId=101748&guidFileName=a06dc777-1090-4992-bfe4-1bc659b1e9e9.pdf.

[127] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Pepco's DC Residential Dynamic Pricing Program Strawman Proposal, Formal Case No. 1130 (DC PSC Apr. 23, 2020), https://edocket.dcpsc.org/apis/api/filing/download?attachId=103237&guidFileName=75e11068-dec1-4769-8972-2c32d5eac814.pdf.

[128] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, First Rate Design Working Group Meeting Minutes, Formal Case No. 1130 (DC PSC May 21, 2020), https://edocket.dcpsc.org/apis/api/filing/download?attachId=103802&guidFileName=42ae1b5e-4998-4673-b224-dac69e06a306.pdf.

[129] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Notice of Final Tariff, Formal Case No. 1130 (DC PSC Jan. 31, 2020), https://edocket.dcpsc.org/apis/api/filing/download?attachId=100495&guidFileName=a1c4325e-438e-4854-b2a8-f24abcedce6c.pdf.

[130] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Transportation Electrification Implementation Plan, Formal Case No. 1130 (DC PSC Oct. 30, 2019), https://edocket.dcpsc.org/apis/api/filing/download?attachId=88301&guidFileName=1b0df7d3-ab24-4a7a-b860-76f21866e7d2.pdf.

energy resource policies.[131] The Hawaii PUC states that it intends to focus its investigation on several issues, including exploration of "advanced rate designs" for customers.[132] The Hawaii PUC also issued an order granting a one year extension of Hawaii Electric Company's interim residential time-of-use rates for electric vehicles until September 30, 2021.[133] The Hawaii PUC stated that it is continuing to investigate rate design, including a long-term replacement for the electric vehicle rates and Hawaii Electric Company's general time-of-use rates for residential customers.[134]

- **Maryland.** On June 12, 2019, the Maryland Public Service Commission (Maryland PSC) finalized a statement of work requesting pilot program proposals as part of its grid modernization proceeding.[135] The Maryland PSC stated that its primary goal of the request for proposals is to identify pilot programs to shape customer load profiles through load shifting, peak shaving, and energy efficiency.[136] On September 15, 2020, BG&E, Delmarva Power & Light Company, and Potomac Electric Power Company submitted their proposals in response to the request.[137] On March 15, 2020, BG&E launched a bring-your-own-thermostat demand response program and a time-of-use electric vehicle charging program.[138] The BG&E program is designed to manage

[131] *In the Matter of Instituting a Proceeding to Investigate Distributed Energy Resource Policies Pertaining to the Hawaiian Electric Companies*, Order No. 36538, Docket No. 2019-0323 (Hawaii PUC Sep. 24, 2019), https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A19I25A84705I00380.

[132] *Id.* at 8.

[133] *In the Matter of Instituting a Proceeding to Investigate Distributed Energy Resource Policies Pertaining to the Hawaiian Electric Companies*, Order No. 37067, Docket No. 2019-0323 (Hawaii PUC Apr. 9, 2019) at 2, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20D13A93326G00047.

[134] *Id.* at 5.

[135] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Docket No. PC44 (Maryland PSC June 12, 2019), https://webapp.psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/PublicConferences/PC44//218.pdf.

[136] *Id.* at 1.

[137] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Docket No. PC44 (Maryland PSC Sep. 15, 2020), https://webapp.psc.state.md.us/newIntranet/AdminDocket/NewIndex3_VOpenFile.cfm?FilePath=//Coldfusion/AdminDocket/PublicConferences/PC44//253.pdf.

[138] EnergyHub, "EnergyHub and Baltimore Gas and Electric Deploy BYOT and EV Charging Programs" (Mar. 15, 2020), https://www.energyhub.com/blog/bge-byot-and-ev-charging-der-programs and

multiple behind-the-meter distributed energy resources under a single platform. The platform allows BG&E to manage an electric vehicle time-of-use rate without the use of utility-owned meters, and instead allowing customers to participate through their own charging equipment and thermostats.

- **New York.** On May 29, 2020, the NYPSC held a technical conference to consider dynamic load management (DLM) resource procurement proposals. DLM stakeholders submitted comments pertaining to requirements for auto-DLM resources; dual participation in multiple programs; performance factor calculations; and eligibility of newly proposed projects versus existing projects or projects already under development.[139] Utilities are required to establish an "auto-DLM" resource category that would require resources to achieve higher performance factors, including more stringent availability and binding multi-year commitments. DLM resources are designed to provide more revenue and programmatic certainty through longer-term agreements between the utility and the DLM resources.[140] On September 17, 2020, the NYPSC approved the utilities' proposed multi-year DLM procurement plans with modifications.[141] In the order, the NYPSC clarified and directed two procurement components: (1) the inclusion of a day-ahead peak shaving Term-DLM Program in which participants provide load relief with as little as 21 hours of advance notice for a specified four-hour period; and (2) a reliability and peak shaving Auto-DLM Program in which participants provide load relief with as little as 10 minutes of advanced notice for a specified four-hour period.[142]

- **New Hampshire.** On May 22, 2020, the New Hampshire Public Utilities Commission (New Hampshire PUC) issued an order requiring continued investigation into how to develop distribution

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https://www.greentechmedia.com/articles/read/bring-your-own-everything-programs-the-future-of-distributed-energy-integration.

[139] *See In the Matter of Energy Storage Deployment Program*, Joint Utilities Reply Comments Term- and Auto-DLM Procurement Process, Case 18-E-0130 (NYPSC Jul. 13, 2020), http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=55960&MNO=18-E-0130.

[140] *See In the Matter of Energy Storage Deployment Program*, Order Establishing Energy Storage Goal and Deployment Policy, Case 18-E-0130 (NYPSC Dec. 13, 2018), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FDE2C318-277F-4701-B7D6-C70FCE0C6266}.

[141] *See In the Matter of Energy Storage Deployment Program*, Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements And Associated Cost-Recovery, Case 18-E-0130 (NYPSC Sept. 17, 2020), http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=55960.

[142] *Id.* at 6.

planning procedures that incorporate grid modernization principles.[143] To limit the cost and operational impacts of anticipated electrification, the New Hampshire PUC and stakeholders largely agreed that alternative rate structures, such as time-varying rates, should be developed and phased in as more distributed energy resources are deployed. As part of its guidance, the New Hampshire PUC reaffirmed that a modern distribution planning process should plan for strategic electrification of transportation and space heating.

[143] *See Investigation Into Grid Modernization*, Guidance on Utility Distribution System Planning And Order Requiring Continued Investigation, Docket No. IR 15-296 (New Hampshire PUC May 22, 2020), https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2020-05-22_ORDER_26358.PDF.

6. Regulatory Barriers to Improved Customer Participation in Demand Response, Peak Reduction, and Critical Period Pricing Programs

Regulatory barriers continue to limit customer participation in demand response programs, including time-based rate programs. Regulators and utilities continue to consider how best to use new streams of information from advanced meters and customer-sited resources to optimize grid operations and provide for greater participation in demand response programs. Outstanding barriers to such participation, recent actions pertaining to these barriers, and recommendations to improve the use of data produced by advanced meters are presented below.

Implementing Time-Based Rates

While adoption and implementation of time-based rate programs continues to increase, as described in Chapter 5, transportation electrification can significantly increase loads, particularly for residential customers. As states consider accelerated electric vehicle deployment, utilities are focusing more on time-based rates and other means to manage electric vehicle charging. In a recent report, the Smart Electric Power Alliance (SEPA) explained that basic time-based rates may not be sufficient to address distribution-level operational challenges expected with large-scale adoption of electric vehicles. If multiple residential customers in the same area program their electric vehicles to begin charging at the start of the off-peak window, the result may unintentionally create coincident load and thereby stress the system.[144] The report notes that, as residential electric vehicle adoption increases, utilities will need to consider developing more sophisticated time-varying rates and potentially consider programs to actively manage electric vehicle charging to reduce distribution level impacts and better align charging with periods when lower cost generation is available.

Utilities are also examining how different distributed energy resources can influence rate designs to incentivize customers to participate in programs that leverage the benefits of flexible loads. For example, Portland General Electric (PGE) considered distributed energy resource and flexible load forecasts to inform its 2019 Integrated Resource Plan.[145] The plan evaluated potential interactions between PGE's existing demand response programs, which include various residential and non-residential time-based rates and direct load control programs, and the effects of combining these demand response programs with distributed energy resources. The analysis included interactions between: solar and storage; participation of electric vehicles in a direct load control program; and the influence of time-of-use pricing on solar

[144] SEPA, *Residential Electric Vehicle Rates That Work* (Nov. 2019) at 12-13, https://sepapower.org/resource/residential-electric-vehicle-time-varying-rates-that-work-attributes-that-increase-enrollment.

[145] Portland General Electric, *Integrated Resource Plan* (July 2019) at 128-133, https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning.

photovoltaic resources, storage, and electric vehicle adoption.[146] PGE also utilized distributed flexibility forecasts to consider how flexible loads would impact the utility's future capacity adequacy assessments.

Lack of Real Time Information Sharing

Some analyses show that limitations to meter data continue to persist. For example, the American Council for an Energy-Efficient Economy (ACEEE) states that advanced meters are being underutilized.[147] Similarly, some state regulatory authorities recently have rejected utility proposals to implement advanced meters because they do not take advantage of all the capabilities and features that advanced meters provide.[148] As mentioned in Chapter 2, states are also removing requirements that utilities provide direct, real-time data on customer energy usage.[149] With broad use of technologies that rely on real-time data, such as distributed energy resources and smart appliances, ACEEE maintains that customer access to real-time data and understanding of the data is important, because a lack of data can impact the customers' ability to manage their energy consumption and realize cost savings. While customer access to data alone does not result in energy savings, ACEEE found that when paired with engagement, pricing strategies, and incentive-based programs, customers modify their behavior and energy use.[150] ACEEE urges regulators to: allow for pilot programs and designs to test and scale advanced meters; create performance incentives in advanced meter approvals; establish clear data access that provides customer's options; require utilities demonstrate the ways they propose to use advanced meters to achieve customer energy efficiency and savings; and require that cost recovery be contingent on actual customer benefits.[151]

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[146] Peak Load Management Alliance, *The Future of Distributed Energy Resources: A Compendium of Industry Viewpoints* (2019) at 8, https://www.peakload.org/assets/resources/PLMA-Future-of-DER-Compendium.pdf.

[147] American Coalition for an Energy Efficient Economy, *Leveraging Advanced Metering Infrastructure To Save Energy* (Jan. 2020) at iv, v, https://www.aceee.org/research-report/u2001#:~:text=Advanced%20metering%20infrastructure%20(AMI)%20can,customers%20save%20energy%20and%20money.&text=ACEEE%20surveyed%2052%20large%20utilities,are%20greatly%20underutilizing%20this%20technology (ACEEE Report).

[148] *See supra* nn.22, 28.

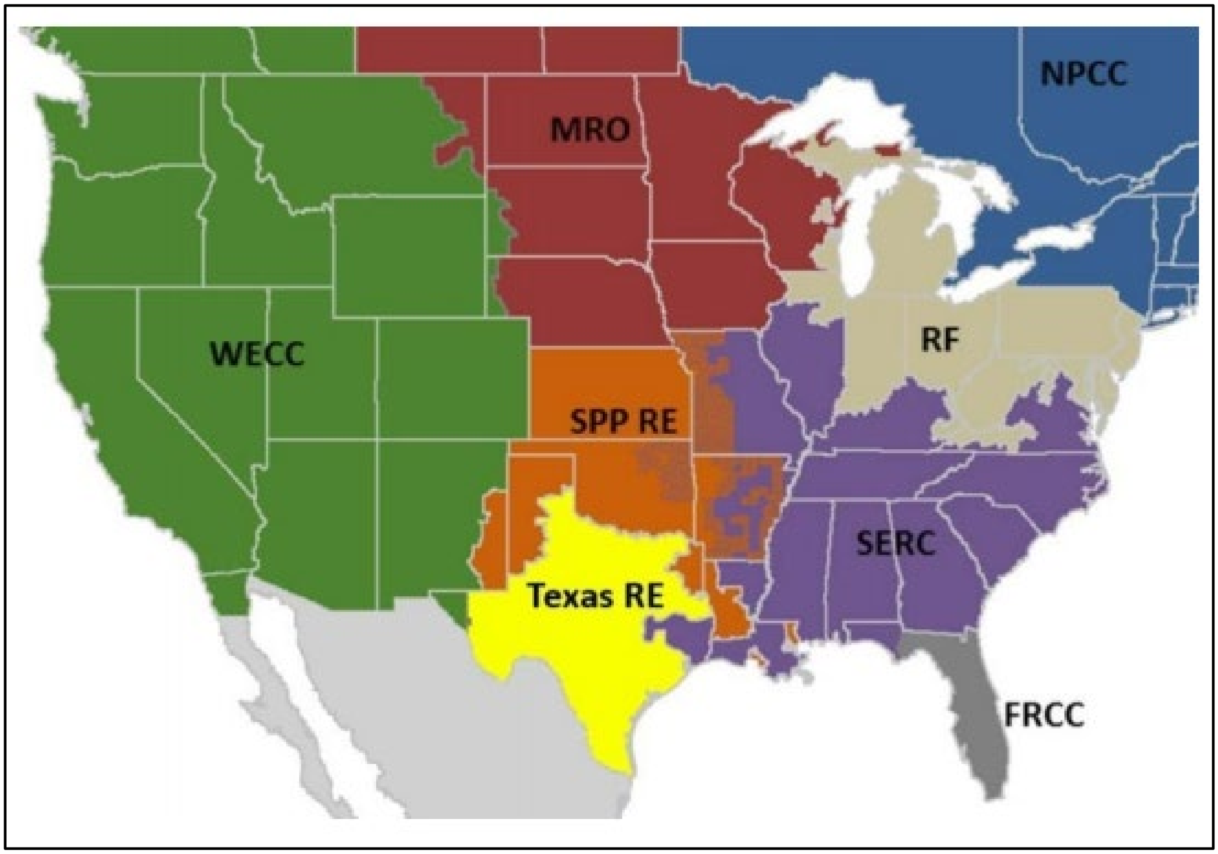
[149] *See supra* n.26.

[150] ACEEE Report at iv, 14.

[151] *Id.* at 42, 43.

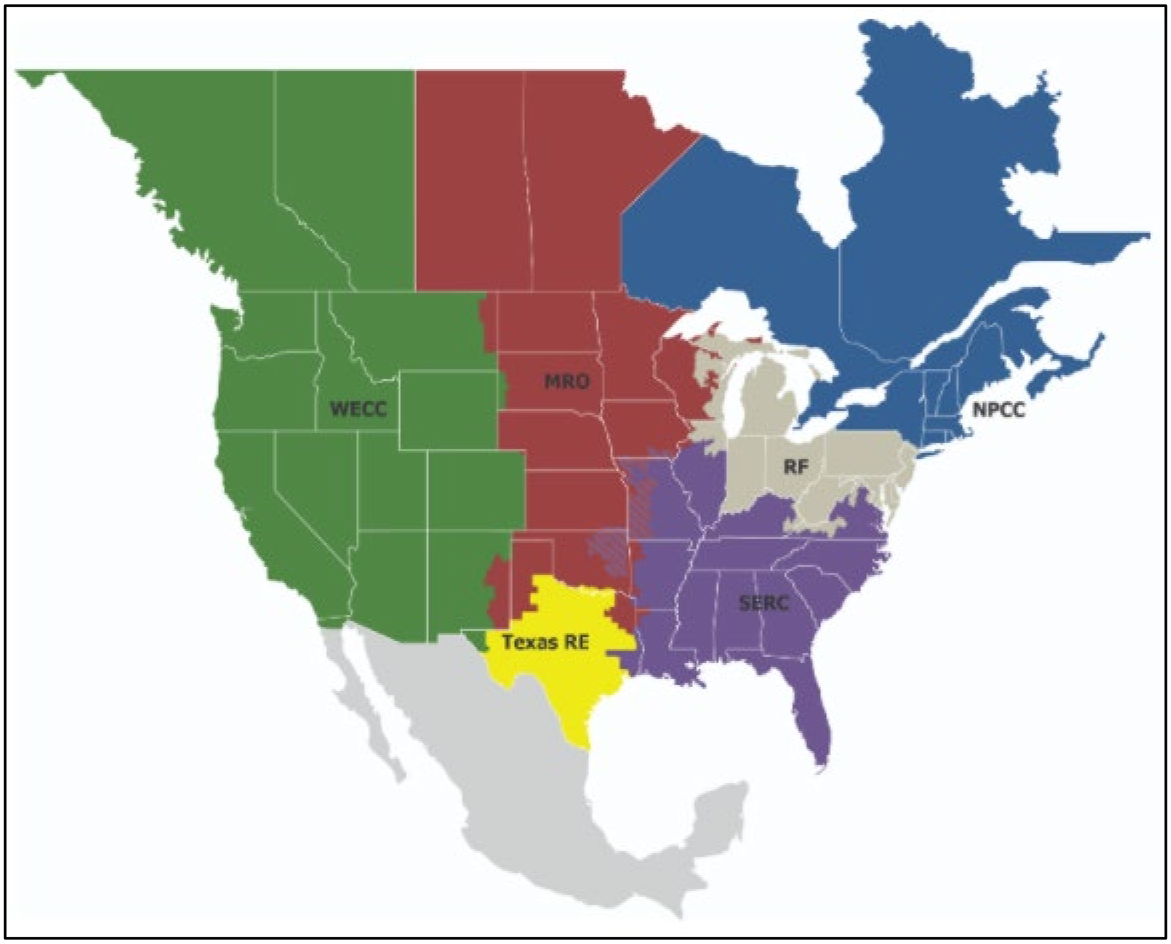
Appendix: Map of NERC Regional Entities

The report assesses advanced meter penetration, retail demand response, and retail dynamic pricing programs by NERC region through 2018. In 2018, 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 and Hawaii are not subject to NERC oversight.



Note that, with the dissolution of SPP RE in 2018, and FRCC in 2019, there are currently six NERC Regional Entities in 2020, as shown below.

On May 4, 2018, FERC approved a joint petition to dissolve the SPP RE and transfer NERC registered entities within the SPP RE footprint to MRO and SERC, effective July 1, 2018. *See NERC, MRO and SERC*, 163 FERC ¶ 61,094 (2018). In addition, on April 30, 2019, FERC approved a separate joint petition to dissolve FRCC as a Regional Entity and transfer NERC registered entities within the FRCC footprint to SERC, effective July 1, 2019. *See NERC, FRCC, and SERC*, 167 FERC ¶ 61,095 (2019). The current NERC regional entities and their territories are shown below.


WECC
MRO
NPCC
RF
SERC
Texas RE

2020 Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

December 2020