2023 Assessment of

Demand Response and Advanced Metering

Staff Report

FEDERAL ENERGY REGULATORY COMMISSION

December 2023

2023 Assessment

of Demand Response and Advanced Metering

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

Staff Report

December 2023

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

Willie Phillips, Chairman

James Danly, Commissioner

Allison Clements, Commissioner

Mark Christie, Commissioner

Acknowledgements

Federal Energy Regulatory Commission Staff Team

Tim Bialecki, Team Lead
Ricardo Charles
Philip Lee
David Schmitt
David Smith
Michael Tita

Table of Contents

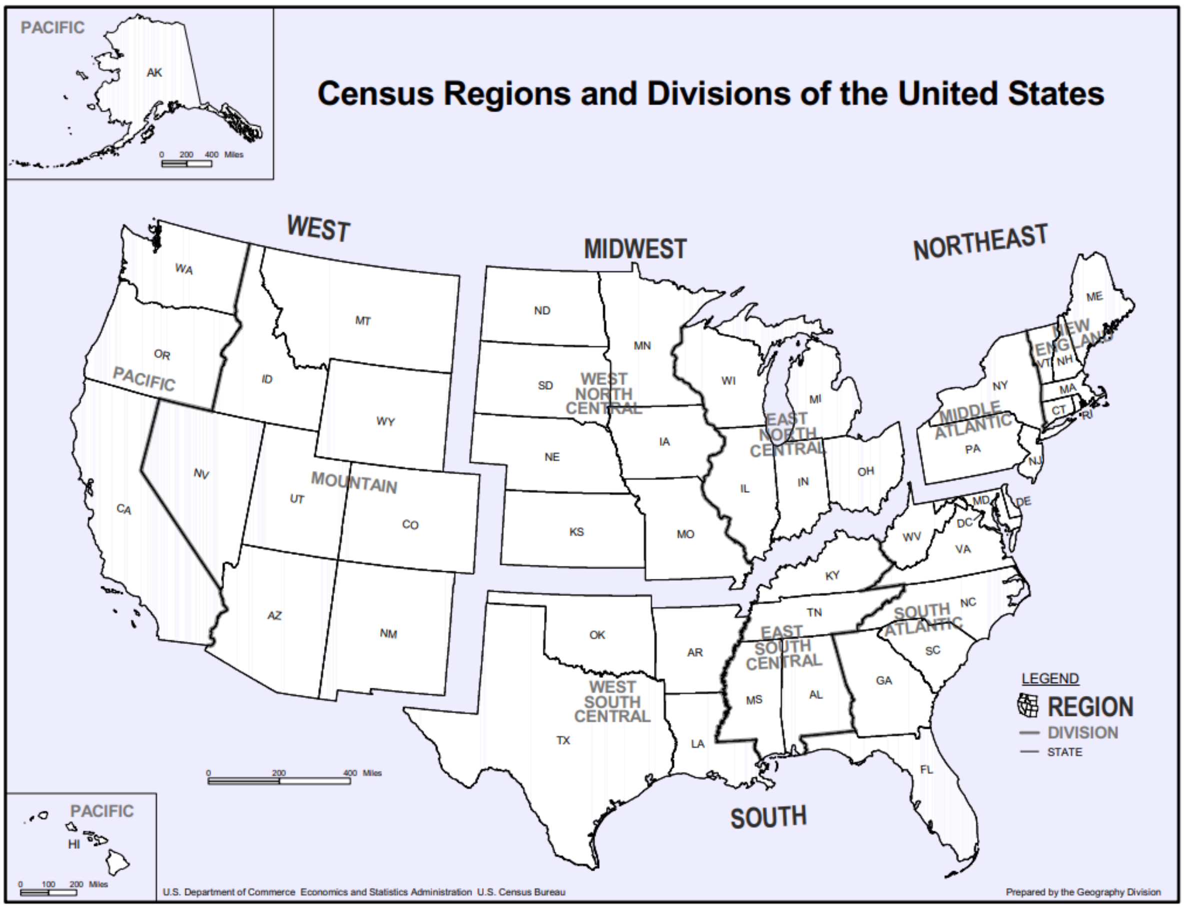
List of Tables and Figures

1. Introduction

This report is the Federal Energy Regulatory Commission (Commission) staff's eighteenth 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 this report is based on publicly available data that is used to estimate demand response potential in retail and wholesale markets.[1]

Consistent with the method first adopted in the 2021 report, this report presents data according to the nine U.S. Census Divisions, broken down by state in the Appendix, to continue to fulfill the regional reporting requirements of EPAct 2005.[2]

Figure 1-1: Map of US Census Divisions



[1] The latest publicly available retail electricity data for the report is for the year 2021 while the latest publicly available wholesale electricity data is for the year 2022.

[2] "[T]he Commission shall prepare and publish an annual report, *by appropriate region*, that assesses demand response resources…." *See* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1252(e)(3), 119 Stat. 594 (2005) (emphasis added).

Highlights of this report include the following:

- From 2020 to 2021, the number of advanced meters[3] in operation in the United States increased by approximately 8 million to a total of 111.2 million, representing a 7.9% annual increase. According to Energy Information Administration (EIA) data, the 111.2 million advanced meters in operation represent over 68% of the 162.8 million total meters in operation across all customer classes. Rates of advanced meter penetration continue to vary by Census Division and customer class, but for the first time since this report has been published, the estimated advanced meter penetration rates nationwide for each of the residential commercial, and industrial customer classes were greater than 60% in 2021.

- In 2021, utilities in the South Atlantic Census Division reported over 25 million advanced meters in operation. Utilities in the East North Central, Pacific, and West South Central Census Divisions each reported over 18 million advanced meters in operation. The total number of advanced meters reported by utilities in the East North Central, East South Central, Pacific, South Atlantic, and West South Central Census Divisions represent advanced meter penetration rates greater than 75%.

- From 2021 to 2022, demand response resource capacity in U.S. wholesale markets increased by approximately 817 MW to a total of 32,920 MW, representing a 2.5% increase. Demand response resource totals increased from 2021 to 2022 in all but one of the wholesale markets. Despite this increase in the capacity (in MW) of demand response participating, the percentage of peak demand that these resources represent fell slightly from 6.6% in 2021 to 6.5% in 2022 because the increase in peak demand outpaced the increase in demand response.[4]

- Utilities and system operators in certain parts of the country are increasingly evaluating opportunities to use load flexibility, as facilitated by the deployment of customer-sited distributed energy resources (DERs) and other energy management devices, to help address the needs of a system with a growing penetration of variable energy resources. For example, California recently

---

[3] As defined by EIA, advanced metering infrastructure (AMI) (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 these 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.

[4] Total peak demand across all RTOs/ISOs was approximately 507,000 MW in 2022. See Table 3-3 for sources for peak demand data.

established a statewide goal to develop 7,000 MW of load flexibility resources to reduce net peak electrical demand, as discussed in further detail in Chapter 4.

- State regulators and utilities continue to consider the advantages and disadvantages of different types of time-varying retail rates, especially in the context of integrating electric vehicles (EVs). Additionally, Michigan, Minnesota, and Missouri have opened proceedings to reconsider whether to allow third-party aggregators of demand response resources to participate in organized markets. Although, as discussed below, the Minnesota Commission voted to table the matter to allow greater exploration of the issue.

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 presents the national and regional penetration rates of advanced meters as well as state developments related to grid modernization and advanced metering. Table 2-1 provides estimates of advanced meter penetration rates from 2007 through 2021. According to EIA data, there were 111.2 million advanced meters installed and operational out of 162.8 million total meters in the United States in 2021. This represents an advanced meter penetration rate of 68.3% and an increase of 8.1 million advanced meters, or 7.9%, from 2020 to 2021. This is the fifth consecutive year that the number of advanced meters has increased by approximately 8 million. The Edison Foundation's Institute of Electric Innovation reported a similar number of advanced meters—115.3 million—in operation in the United States in 2021.

Table 2-1: Estimates of Advanced Meter Penetration Rates in the United States

Data Source	Data as Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2008 FERC Survey[1]	Dec 2007 (FERC)	6.7	144.4	4.7%
2010 FERC Survey[1]	Dec 2009 (FERC)	12.8	147.8	8.7%
2012 FERC Survey[1]	Dec 2011 (FERC)	38.1	166.5	22.9%
2011 Form EIA-861[2]	Dec 2011 (EIA)	37.3	144.5	25.8%
2012 Form EIA-861[2]	Dec 2012 (EIA)	43.2	145.3	29.7%
2013 Form EIA-861[2]	Dec 2013 (EIA)	51.9	138.1	37.6%
2014 Form EIA-861[2]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[2]	Dec 2015 (EIA)	64.7	150.8	42.9%
2016 Form EIA-861[2]	Dec 2016 (EIA)	70.8	151.3	46.8%
2017 Form EIA-861[2]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[2]	Dec 2018 (EIA)	86.8	154.1	56.4%
2019 Form EIA-861[2]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[3]	Dec 2019 (IEI)	99.0	157.2	63.0%
2020 Form EIA-861[2]	Dec 2020 (EIA)	103.1	159.7	64.6%
Institute for Electric Innovation[3]	Dec 2020 (IEI)	107.4	159.7	67.2%
2021 Form EIA-861[2]	Dec 2021 (EIA)	111.2	162.8	68.3%
Institute for Electric Innovation[3]	Dec 2021 (IEI)	115.3	162.8	70.8%

Sources: [1]FERC, *Assessment of Demand Response and Advanced Metering* 2008-2012. [2]EIA-861 Advanced Metering data files 2011-2021. [3]IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* 2021. The IEI report provides only projections for the total number of advanced meters for 2020 and 2021.

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

Figure 2-1 shows advanced meter growth in the United States from 2007 through 2021. Since 2007, the number of advanced meters in operation has increased by 104.5 million, from 6.7 million meters in 2007 to approximately 111.2 million meters in 2021. Over that same period, the advanced meter penetration rate increased from 4.7% to 68.3%.

Figure 2-1: Advanced Meter Growth (2007–2021)[5]

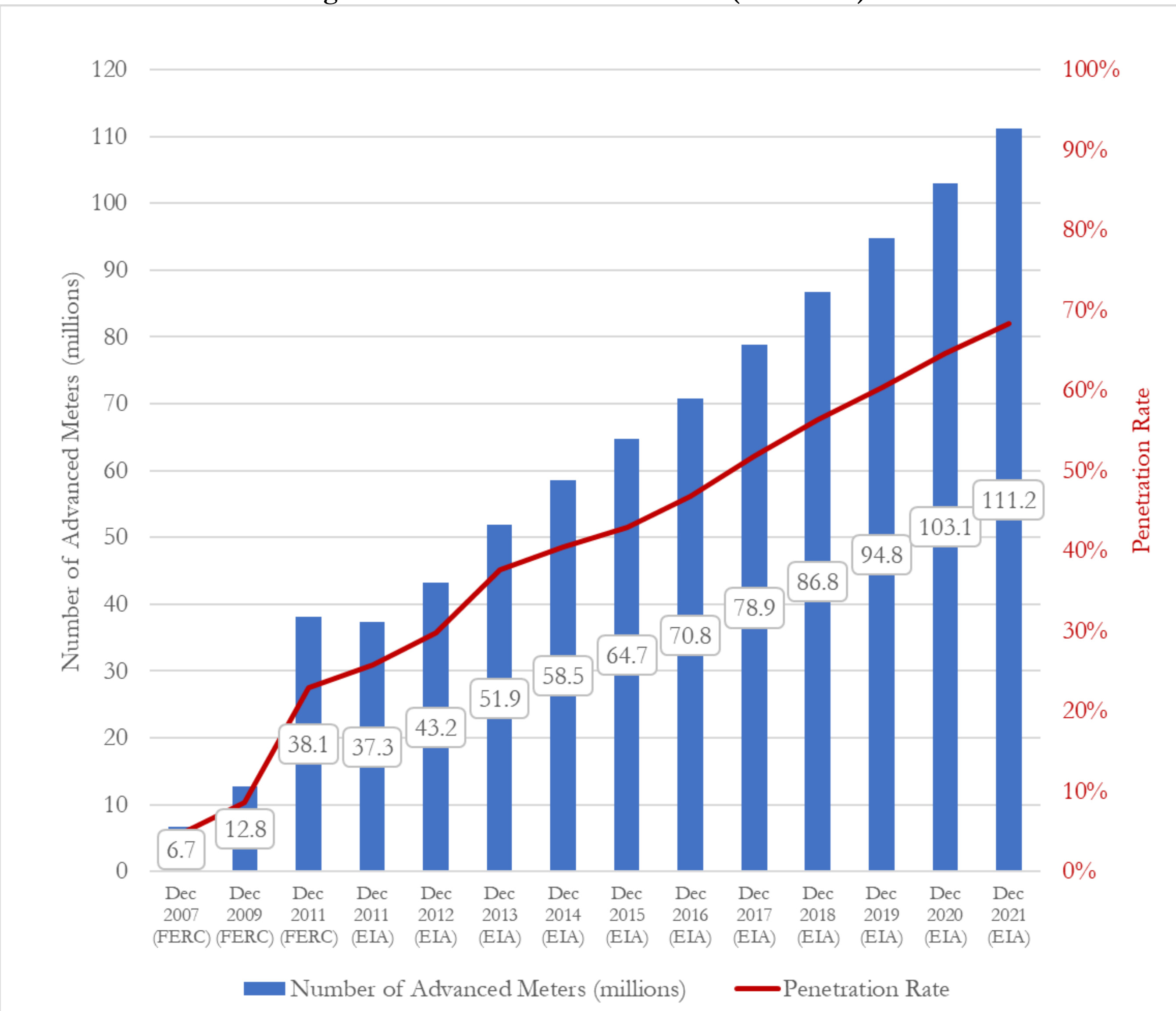


Table 2-2 below provides estimates of advanced meter penetration rates by Census Division and retail customer class for 2021. Utilities reported aggregate totals of advanced meters that represent penetration rates above 75% in five of the nine Census Divisions. As shown in Table 2-2, utilities in the West South Central Census Division reported advanced meter totals that represent an advanced meter penetration rate

---

[5] The left axis, Number of Advanced Meters (millions), corresponds to the blue columns. The right axis, Penetration Rate, corresponds to the red line on the chart.

of 86.2%, the highest rate reported by utilities in any Census Division. In contrast, utilities in the Middle Atlantic and New England Census Divisions reported totals representing aggregate advanced meter penetration rates below 50%.

Table 2-2 also shows the overall advanced meter penetration rate for the residential, commercial, and industrial customer classes. For the first time, the total advanced meter penetration rate across all regions for each of the customer classes was greater than 60%. Overall, utilities reported the highest number of advanced meters in the residential class, which represented a penetration rate of 68.7%. The reported totals for the commercial and industrial customer classes followed closely, with advanced meter penetration rates of 65.6% and 63.2%, respectively. However, the advanced meter penetration rates for each customer class varied among Census Divisions. For example, the East North Central, East South Central, South Atlantic, and West South Central Census Divisions had the highest advanced meter penetration rates in the residential customer class, while the Middle Atlantic, Mountain, New England, and West North Central Census Divisions had the highest advanced meter penetration rates in the industrial customer class. The Pacific Census Division had the highest advanced meter penetration rate in the commercial customer class.

Table 2-2: Advanced Meter Penetration Rate by Census Division and Customer Class (2021)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	77.5%	73.1%	63.3%	77.0%
East South Central	78.9%	74.5%	63.8%	78.2%
Middle Atlantic	41.3%	36.7%	49.0%	40.7%
Mountain	57.9%	52.0%	60.9%	57.2%
New England	22.9%	23.8%	26.1%	23.1%
Pacific	77.9%	79.6%	64.2%	78.1%
South Atlantic	77.3%	72.5%	56.1%	76.7%
West North Central	53.7%	52.4%	65.5%	53.7%
West South Central	86.7%	83.8%	71.9%	86.2%
All Regions	68.7%	65.6%	63.2%	68.3%

Source: 2021 Form EIA-861 Advanced_Meters_2021 data file and 2021 Form EIA-861 Utility_Data_2021 data file.

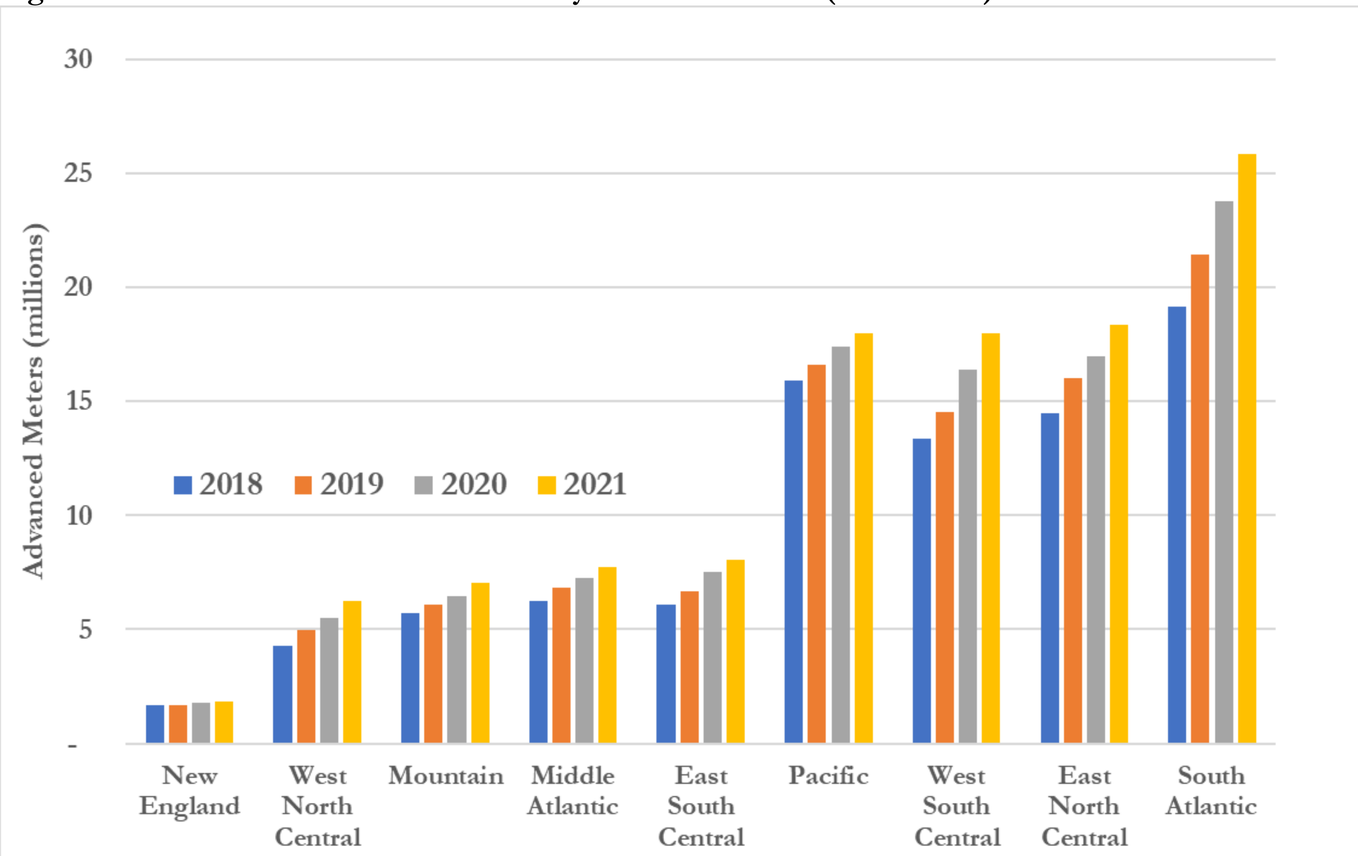
Note: Transportation sector data collected by EIA contain a relatively small number of meters and are not reported separately here. Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data.

Figure 2-2 shows the number of advanced meters in operation by Census Division from 2018 to 2021. Over this period, the number of advanced meters showed an upward trend across all Census Divisions. Utilities in all nine Census Divisions reported more advanced meters in operation in 2021 compared with 2020. The South Atlantic Census Division experienced the largest increase in the number of advanced meters from 2020 to 2021, where utilities reported just over 2 million more advanced meters, representing an increase of 9%. Utilities that reported the largest increases in the number of advanced meters in the South Atlantic Census Division include Virginia Electric & Power Co in Virginia, Duke Energy Florida, and Appalachian Power Co in West Virginia, which reported more than 530,000, 516,000, and 117,000 additional advanced meters in 2021, respectively.

The West North Central Census Division experienced the largest percentage increase in the number of advanced meters from 2020 to 2021, where utilities reported approximately 770,000 more advanced meters, representing an increase of 14%. Union Electric Co, Dakota Electric Association, and ALLETE Inc. saw the largest increases in the census division, reporting more than 319,000, 63,000, and 19,000 additional advanced meters in 2021 compared to 2020, respectively.

Utilities in the East North Central, East South Central, West South Central, Pacific, Middle Atlantic, Mountain, and New England Census Divisions reported approximately 1.4 million, 559,000, 1.6 million, 600,000, 496,000, 587,000, and 17,000 more advanced meters in 2021 compared to 2020, respectively.

Figure 2-2: Number of Advanced Meters by Census Division (2018 – 2021)



Development and Issues in Advanced Metering

State Legislative and Regulatory Activities Related to Advanced Metering

Below is a discussion of several states that have taken actions related to advanced metering infrastructure (AMI).

Massachusetts. As mentioned in last year's report, in July 2021, National Grid, Eversource Energy, and Unitil each filed their 2022-2025 proposed Grid Modernization Plan with the Massachusetts Department of Public Utilities (Massachusetts DPU). In September 2021, the Massachusetts DPU bifurcated its investigation of the proposed plans to consider grid modernization plans and new AMI implementation plans in two, separate parallel tracks.[6] Within their separate proposals, National Grid, Eversource Energy, and Unitil provided estimated costs for: (1) new grid investments, such as advanced load flow platforms, Distributed Energy Resource Management Systems (DERMS) platforms, and verification systems; (2) customer-facing investments, including cybersecurity upgrades and customer engagement programs; and (3) installation or upgrades of millions of new AMI electric meters throughout their service territories.[7] The National Grid, Eversource Energy, and Unitil proposals include cost recovery amounts and mechanisms for both investments in preauthorized categories of activities and additional incremental grid modernization investments.[8] In November 2022, the Massachusetts DPU preauthorized the following AMI deployment investments: Eversource's proposal to spend $232 million through 2028;[9] National Grid's proposal to spend $273.4 million through 2027;[10] and Unitil's proposal to spend $11.2 million through 2025.[11]

Missouri. On January 7, 2022, Evergy Metro, Inc and Evergy Missouri West (collectively, Evergy Missouri) filed a rate case with the Missouri Public Service Commission (Missouri PSC).[12] The parties set forth eight issues for the Missouri PSC's consideration, including the prudency of switching out AMI meters for AMI-Service Disconnect meters (AMI-SD) meters.[13] In December 2022, the Missouri PSC found that it was not prudent to wholly retire and replace functioning AMI meters with AMI-SD meters because the AMI meters had significant remaining life and the benefits did not outweigh the costs of early replacement.[14] The

---

[6] *See Order on Interim Continuation of Grid Modernization Programs and Revised Grid Modernization Factor Tariffs,* Docket Nos. 21-80/21-81/21-82 (Massachusetts DPU Dec. 30, 2021) at 3, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/14353436.

[7] *Order on New Technologies and Advanced Metering Infrastructure Proposals*, Docket Nos. 21-80-B/21-81-B/21-82-B (Massachusetts DPU Nov. 30, 2022) at 10-55, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15824167.

[8] *Id.* at 57-63.

[9] *Id.* at 238.

[10] *Id.* at 258.

[11] *Id.* at 277.

[12] *In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service, Docket No. ER-2022-0129 &In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service*, Docket No. 2022-0130 (Missouri PSC December 8, 2022) at 5, https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=ER-2022-0129&attach_id=2023010739.

[13] The difference between the regular AMI meters and AMI-SD meters are that AMI-SD meters can remotely connect and disconnect electric service. *Id.* at 8, 44 & 49.

[14] *Id.* at 51-52.

Missouri PSC only allowed recovery of AMI-SD meter investments under certain circumstances, including if AMI-SD meters will replace manual meters or AMI meters that are not functioning.[15]

New Jersey. On November 9, 2022, the New Jersey Board of Public Utilities (New Jersey BPU) accepted a consultant's report that includes a set of recommendations and frameworks to modernize New Jersey's electric grid through a series of interconnection reforms and developing an integrated DER plan.[16] The report suggests that AMI and other advanced distribution operations platforms could be used to streamline the interconnection application process.[17] The report recommends that the New Jersey BPU implement AMI or other advanced distribution operations platforms to: (1) facilitate deployment and safe operation of DERs; and (2) manage two-way energy delivery.[18] The report also recommends that the New Jersey BPU modernize data access and availability, data privacy standards, and cybersecurity protections including those under consideration in the New Jersey BPU's AMI Data Access proceeding for more efficient DER interconnection methods.[19] The report further lists suggestions from New Jersey's individual electric distribution companies to consider interconnection application process efficiencies through deployment of AMI.[20]

New Mexico. On May 31, 2023, the New Mexico Public Regulation Commission (New Mexico PRC) issued an order requiring New Mexico PRC staff to conduct a cost-benefit analysis of Public Service Company of New Mexico's Grid Modernization Plan.[21] The New Mexico PRC found it appropriate to undertake such a study because of the need to weigh the cost of grid modernization and its benefits. The New Mexico PRC also found that several other state utility commissions have conducted similar studies when considering grid modernization investments.[22]

Rhode Island. On November 18, 2022, Rhode Island Energy submitted its Advanced Metering Functionality Business Case to Rhode Island Public Utilities Commission (Rhode Island PUC) that details

[15] *Id.* at 52.

[16] Guidehouse Inc., Grid Modernization Study (New Jersey BPU August 24, 2022), https://nj.gov/bpu/pdf/reports/NJBPU%20Grid%20Modernization%20Final%20Report.pdf.

[17] *Id.* at 43.

[18] *Id.*

[19] *Id.* at 44.

[20] *Id.*

[21] *In The Matter of Public Service Company of New Mexico's Application for Authorization to Implement Grid Modernization Components that Include Advanced Metering Infrastructure and Application to Recover the Associated Costs Through a Rider, Issuance of Related Accounting Orders, and Other Associated Relief*, Docket No. 22-00058-UT (New Mexico PRC May 31, 2023) at 9.

[22] *Id.* at 10-13.

full-scale deployment of advanced metering functionality (AMF).[23] AMF refers to the "functionality provided by advanced meters" that results from deployment of AMI and the associated software required to use the advanced meter data efficiently.[24] Rhode Island Energy plans to replace advanced meter reading technology with AMF.[25] Specifically, Rhode Island Energy proposes to replace 524,677 electric AMR meters with electric AMF meters at a cost of $102.9 million by December 2025.[26] Rhode Island Energy's plan would allow customers to participate in AMF-enabled, time-varying rates and other rate design programs.[27] Rhode Island Energy also proposes to implement a customer engagement plan that will educate its customers about AMF and how to utilize the AMF platform.[28]

Collaborative Industry-Government Efforts

Following the issuance of Order No. 2222, the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO) convened an initiative focused on DER integration and compensation to "support state members in understanding the impact of their decision making related to the connection, operation, and compensation of DERs---within the distribution grid, bulk power system, and wholesale energy markets."[29] In March 2023, the NARUC-NASEO Distributed Integration and Compensation Initiative published a report that summarized industry expert recommendations for supporting DER aggregator participation in wholesale markets and operations in line with FERC Order No. 2222.[30] The report recommends that state policy makers assess where utilities have

[23] *Advanced Metering Functionality Business Case Book 1 of 3*, Docket No. 22-49-EL (Rhode Island PUC Nov. 18, 2022) at 1, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-11/2249-RIE-AMFPlan-Book1%2011-18-22.pdf.

[24] *Id.* at 1.

[25] *Advanced Metering Functionality Business Case and Attachments Book 2 of 3*, Docket No. 22-49-EL (Rhode Island PUC Nov. 18, 2022) at 1, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-11/2249-RIE-AMFPlan-Book2%2011-18-22.pdf.

[26] *Id.* at 3, 165 & Attachment D at 5.

[27] *Id.* at 179 & 182.

[28] *Id.* at 103.

[29] *See* NARUC Center for Partnerships and Innovation, NARUC-NASEO Distributed Energy Resource Integration and Compensation, https://www.naruc.org/cpi-1/deric/.

[30] NARUC & NASEO, Distributed Energy Resources (DER) Integration and Compensation Initiative: Summary of Expert Recommendations for Supporting DER Aggregator Participation in Wholesale Markets and Operations in Line with FERC Order 2222 (March 2023), https://www.naseo.org/data/sites/1/documents/publications/NASEO_NARUC_Summary_of_Issues_Interactive.pdf.

deployed AMI and assess how AMI capabilities can be leveraged to support DER deployment.[31] The report also recommends that state policy makers determine metering and submetering requirements, consider how these requirements interact with retail billing, and evaluate required communications between DERs, DER Aggregators, and electric distribution companies to consider what additional communication technology investments may be needed.[32]

[31] *Id.* at 3.

[32] *Id.* at 4.

3. Annual Resource Contribution of Demand Resources

This chapter summarizes the annual potential resource contribution from retail and wholesale demand response programs at the national and regional levels using the latest publicly available data from EIA and Regional Transmission Organizations/Independent System Operators (RTOs/ISOs). As noted earlier in the report, FERC staff does not independently verify the accuracy of EIA data, but rather reports the data as they were reported by EIA.

Retail Demand Response Programs

Table 3-1 below provides annual peak demand savings for 2020 and 2021 from retail demand response programs in each of the nine Census Divisions. 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."[33] From 2020 to 2021, potential peak demand savings in the United States decreased slightly by approximately 248 MW, or 0.8%, from 29,470 MW to 29,222 MW. This slight decrease can be attributed to the East North Central, Middle Atlantic, and Pacific Census Divisions, where utilities reported less potential peak demand savings in 2021 compared with 2020.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2020 and 2021)

Census Division	Annual Potential Peak Demand Savings (MW)		Year-over-Year Change	
	2020	2021	MW	%
East North Central	4,909.7	4,500.2	-409.5	-8.3%
East South Central	3,797.0	4,536.8	739.8	19.5%
Middle Atlantic	1,504.8	837.7	-667.1	-44.3%
Mountain	2,142.9	2,336.8	193.9	9.0%
New England	248.5	293.8	45.3	18.2%
Pacific	2,346.3	1,377.1	-969.1	-41.3%
South Atlantic	7,197.1	7,678.7	481.6	6.7%
West North Central	4,689.5	4,840.2	150.7	3.2%
West South Central	2,634.2	2,820.8	186.5	7.1%
Total	**29,470.2**	**29,222.2**	**-248.0**	**-0.8%**

Source: 2021 Form EIA-861 Utility_Data_2021 data file, 2021 Form EIA-861 Demand_Response_2021 data file, 2020 Form EIA-861 Utility_Data_2020 data file, 2020 Form EIA-861 Demand_Response_2020 data file.

Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data, and Commission staff is aware that there may be inconsistencies between data reported to EIA and other data sources.

[33] EIA, 2020 Form EIA-861 Instructions at 16. *See also* 2020 Form EIA 861 Schedule 6, Part B: Demand Response Programs.

Figure 3-1 below shows changes in potential peak demand savings from retail demand response programs in each Census division from 2018 through 2021. Over this period, the amount of potential peak demand savings varied significantly for each Census Division. From 2020 to 2021, utilities in six of the nine Census Divisions experienced increases in potential peak demand savings. In aggregate, utilities in the East South Central Division reported 740 MW more potential peak demand savings in 2021, representing a 19.5% increase and the largest increase among Census Divisions. This increase was primarily attributable to one cooperative that reported approximately 939 MW of additional peak demand savings. In the Mountain Census Division, the notable increases were from Holy Cross Electric Association, Salt River Project, and United Power, which reported approximately 38 MW, 37 MW, and 31 MW more potential peak demand savings in 2021 than 2020, respectively. Connecticut Light & Power Company reported 35 MW more potential peak demand savings in the New England Census Division. In the South Atlantic Census Division, the largest increases were from Duke Energy Florida and Potomac Electric Power Company in Maryland, which reported increases of approximately 355 MW and 248 MW, respectively. Midwest Electric Member Corporation, Great River Energy, and Union Electric Company reported approximately 137 MW, 80 MW, and 61 MW more potential peak demand savings in the West North Central Census Division, respectively. Finally, the largest increase in the West South Central Census Division was from Entergy Arkansas, which reported approximately 347 MW more potential peak demand savings.

The total decrease in potential peak demand savings from 2020 to 2021 was concentrated in the East North Central, Middle Atlantic, and Pacific Census Divisions. The Pacific Census Division experienced the largest decrease, with utilities in aggregate reporting 969 MW less potential peak demand savings in 2021 compared with 2020. Utilities in the East North Central Census Division reported approximately 410 MW less potential peak demand savings, while utilities in the Middle Atlantic Census Division reported approximately 667 MW less potential peak demand saving in 2021. The decrease in the Middle Atlantic Census Division was mainly due to utilities in Pennsylvania reporting, in aggregate, approximately 540 MW less potential peak demand savings in 2021 compared to 2020.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2018 – 2020)

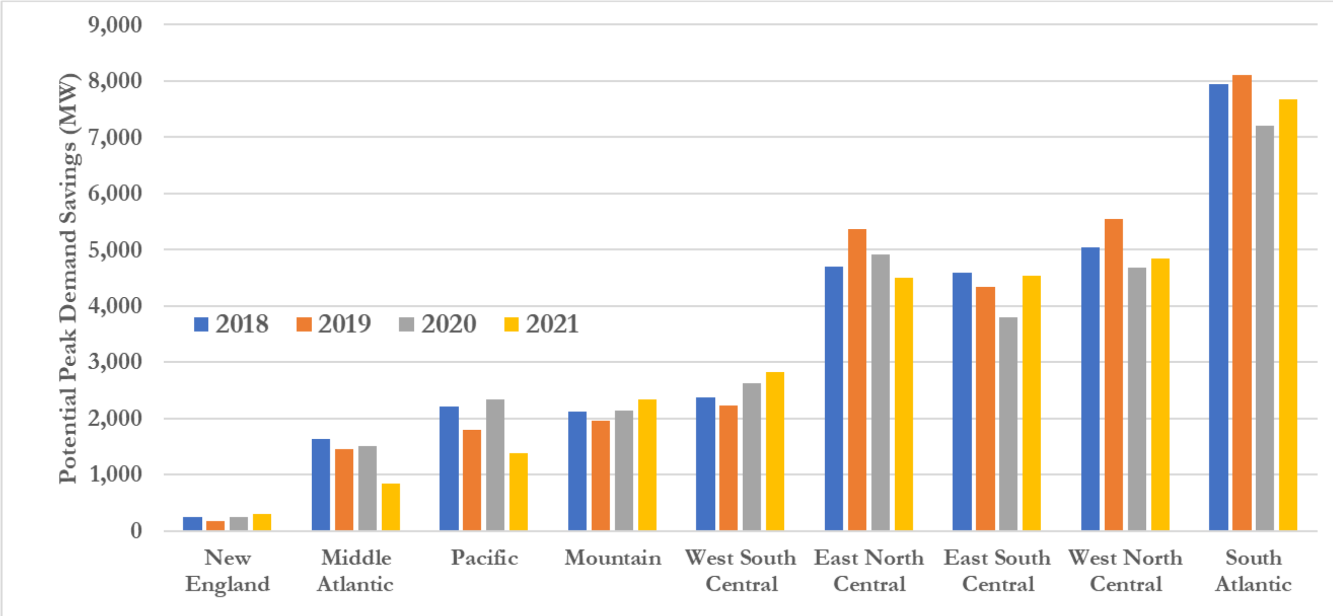


Table 3-2 below shows the relative contribution of retail potential peak demand savings from the residential, commercial, and industrial customer classes in 2021. Overall, utilities reported the largest potential peak demand savings—approximately 13,871 MW—from the industrial class, representing 47% of the total reported potential peak demand savings. The residential and commercial customer classes accounted for 30% and 23% of the total potential peak demand savings, respectively. The customer class with the largest amount of potential peak demand savings varied among Census Divisions. The residential class had the largest amounts of potential peak demand savings in the Mountain, South Atlantic, and West North Central Census Divisions. The commercial class had the largest amounts of potential peak demand savings in the Middle Atlantic, New England, and Pacific Census Divisions. The industrial class had the largest amounts of potential peak demand savings in the East North Central, East South Central, and West South Central Census Divisions.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division and Customer Class (2021)

Census Division	Customer Class			
	Residential (MW)	Commercial (MW)	Industrial (MW)	All Classes (MW)
East North Central	811.5	853.7	2,835.0	4,500.2
East South Central	347.3	115.2	4,074.3	4,536.8
Middle Atlantic	148.7	436.2	252.8	837.7
Mountain	1,067.8	401.6	867.5	2,336.8
New England	86.4	141.7	65.7	293.8
Pacific	415.1	671.1	291.0	1,377.1
South Atlantic	3,364.5	2,201.7	2,112.5	7,678.7
West North Central	1,896.9	1,143.5	1,799.8	4,840.2
West South Central	566.9	681.6	1,572.3	2,820.8
Total	**8,705.1**	**6,646.2**	**13,870.8**	**29,222.2**

Source: 2021 Form EIA-861 Demand_Response_2021 data file and 2021 Form EIA-861 Utility_Data_2021 data file.

Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data.

Wholesale Demand Response Programs

Table 3-3 below estimates participation in the seven RTO/ISO[34] wholesale demand response programs in 2021 and 2022. Demand response participation in the wholesale markets increased by approximately 817 MW, or 2.5%, from 2021 to 2022. On a regional basis, demand response totals increased in all but one of the wholesale markets. PJM reported approximately 681 MW more demand response resources in 2022, which represented the largest annual increase among the RTOs/ISOs. Based on the reported data, 6.5% of the wholesale market peak demand for all RTOs/ISOs could be met by demand response resources in 2022, which is slightly less than the 6.6% reported in 2021.

[34] The RTOs/ISOs include California Independent System Operator (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 Response Resource Participation in RTOs/ISOs (2021 & 2022)

RTO/ISO	2021		2022		Year-over-Year Change	
	Demand Response Resources (MW)	Percent of Peak Demand[8]	Demand Response Resources (MW)	Percent of Peak Demand[8]	MW	Percent
CAISO[1]	3,582.4	8.1%	3,955.8	7.6%	373.4	10.4%
ERCOT[2]	4,354.5	5.9%	3,561.6	4.4%	-792.9	-18.2%
ISO-NE[3]	533.7	2.3%	573.0	2.3%	39.3	7.4%
MISO[4]	12,197.0	10.2%	12,390.0	10.2%	193.0	1.6%
NYISO[5]	1,345.5	4.4%	1,483.3	4.9%	137.8	10.2%
PJM[6]	9,914.0	6.8%	10,594.6	7.3%	680.6	6.9%
SPP[7]	176.2	0.3%	361.8	0.7%	185.6	105.3%
Total	**32,103.4**	**6.6%**	**32,920.1**	**6.5%**	**816.7**	**2.5%**

Sources for demand resource data: [1] CAISO, 2022 Annual Reports on Market Issues and Performance. Totals for Figure 1.31 were confirmed with the CAISO Department of Market Monitoring. The CASIO 2021 value for demand resources was revised to reflect the totals confirmed by the CAISO Department of Market Monitoring; [2] Estimated based on ERCOT, 2021 and 2022 Annual Reports of Demand Response in the ERCOT Region; [3] ISO-NE, Monthly Statistics Report, presented at the July 2021 Resources Working Group Meetings and the ISO-NE Monthly Market Operations Report July 2023; [4] Potomac Economics, 2021 and 2022 State of the Market Reports for the MISO Electricity Markets; [5] NYISO, 2021 and 2022 Annual Reports on Demand Side Management Programs of the New York Independent System Operator, Inc.; [6] PJM, 2021 and 2022 Demand Response Operations Markets Activity Reports. Totals represent "unique MW"; [7] SPP, 2021 and 2022 State of the Market Reports; [8] Sources for peak demand data include: CAISO 2021 and 2022 Annual Reports on Market Issues and Performance; ERCOT 2021 & 2022 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report; Potomac Economics, 2021 and 2022 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2021 and 2022; 2021 and 2022 PJM State of the Market Report, Vol. 2; SPP 2021 and 2022 State of the Market Reports.

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

In CAISO, demand response resources increased by approximately 373 MW, or 10.4%, from 3,582 MW in 2021 to 3,956 MW in 2022. Third-party demand response capability increased 30% from 2021 to 2022. Third party demand response is operated by non-utility providers under contract to supply demand response for utilities. In contrast, utility demand response capability decreased by 20% compared to 2021.[35]

[35] CAISO, *2022 Annual Report on Market Issues and Performance* 29 (July 2023), http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf.

The decline in utility demand response is attributable, in part, to fewer demand response resources and the reduction in a multiplier that is added to utilities' demand response values.[36]

In ERCOT, demand response resources decreased by approximately 793 MW, or 18.2%, from 4,355 MW in 2021 to 3,562 MW in 2022. ERCOT experienced a decrease of 713 MW in demand response resources providing frequency response through the Responsive Reserve Service program. There was also a decrease of 80 MW in resources providing Emergency Response Service.

ISO-NE reported approximately 573 MW of Active Demand Capacity Resources enrolled in August 2022, the month with the highest peak demand in ISO-NE. This represents a 39 MW, or 7.4%, increase in demand response capability in ISO-NE compared to 534 MW in 2021.

MISO experienced an increase in demand response resources of approximately 193 MW, or 1.6%, from 12,197 MW in 2021 to 12,390 MW in 2022. From 2021 to 2022, Load Modifying Resource[37] capability increased by 492 MW. In contrast, Demand Response Resource Type I and II capability and Emergency Demand Response capability decreased by 117 MW and 329 MW, respectively.[38]

In NYISO, demand response resources increased by approximately 138 MW, or 10.2%, from 1,346 MW in 2021 to 1,483 MW in 2022. From 2021 to 2022, enrollment in NYISO's reliability-based demand response programs and Demand-Side Ancillary Service Program increased by approximately 65 MW and 73 MW, respectively.

PJM experienced the largest annual increase in demand response resources. From 2021 to 2022, the total demand response resources increased by approximately 681 MW, or 6.9%, from 9,914 MW in 2021 to 10,595 MW in 2022. The increase in demand response participation is due to increased participation in the Economic and Load Management programs. Enrollment in Economic programs increased by 531 MW,

---

[36] The California PUC calculates credited demand response by multiplying the reported capacity by a number of adders. One adder is the planning reserve margin, which decreased from 15 percent to 9 percent in 2022. *See* CAISO, *2022 Annual Report on Market Issues and Performance* 50 fn. 68 (July 2023), http://www.caiso.com/Documents/2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf.

[37] Load Modifying Resources (LMRs) are Demand or Behind the Meter Generation resources that are available to MISO to meet its resource adequacy requirements and can be called up by MISO during a capacity or transmission emergency. MISO, Resource Adequacy Business Practice Manual BPM-011-r29 15 (October 1, 2023).

[38] The values reported for Demand Response Resource Type I and II, and Emergency Demand Response may include resources cross-registered as Load Modifying Resources. *See* Potomac Economics, *2022 State of the Market Report for the MISO Electricity Markets* 102-103 (June 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

while enrollment in Load Management programs increased by 241 MW. However, PJM experienced a 120 MW decrease in enrollment in its Price Responsive Demand program.[39]

SPP reported a total demand response capability of approximately 362 MW from 140 demand response resources. This represents a 186 MW increase from 2021, when SPP reported a total of 176 MW of demand response capability.

Demand Response Deployments

RTOs and ISOs deploy demand response resources to balance supply and demand and to reduce the cost of dispatching additional generation. Below is a discussion of demand response events since the last report and updates about notable demand response events.

In December 2022, Winter Storm Elliott brought severe cold weather to a large swath of the country, which stressed the bulk-power system, led to new demand records, and compelled multiple regions to employ emergency operating procedures.[40] On December 23, 2022, PJM dispatched demand response resources with capacity commitments, known as Load Management resources. PJM dispatched what it anticipated to be 4,336 MW of quick lead time (30 minutes) and short lead time (60 minutes) Load Management resources, but PJM estimates that, based on after-the-fact customer data, only about 1,100 MW of actual load reductions were implemented.[41] On December 24, 2022, PJM was approaching morning peak under critical capacity conditions, and system operators dispatched all Load Management resources with a total capacity commitment of 7,522 MW. Based on their analysis of customer data after the fact, PJM estimates that actual load reductions were approximately 2,400 MW.[42]

The MISO region also experienced abnormally cold temperatures on December 23, 2022, which drove high demand for heating and led MISO into a Maximum Generation Event Step 2a, a procedural step that allowed the system operator to access demand response resources.[43] MISO sent scheduling instructions to

---

[39] The values reported for Load Management and Economic programs may include resources registered in both programs. The total demand response resource participation reported here represents "unique MW." According to PJM, unique MW "represent total estimated demand reduction assuming full Load Management and Economic reductions." *See* PJM, *2022 Demand Response Operations Markets Activity Report* 4 (July 2023), https://www.pjm.com/-/media/markets-ops/dsr/2022-demand-response-activity-report.ashx.

[40] FERC, *FERC, NERC to Open Joint Inquiry into Winter Storm Elliott*, Press Release (December 28, 2022), https://www.ferc.gov/news-events/news/ferc-nerc-open-joint-inquiry-winter-storm-elliott.

[41] PJM, Winter Storm Elliott: Event Analysis and Recommendation Report 42 (July 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

[42] *Id.* at 42.

[43] MISO Reliability Subcommittee, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* 3-4, (January 2023),

3 GW of Load Modifying Resources at 5:37 PM to offset increasing load and continue exports to neighbors that were also experiencing tight conditions.[44] Based on analysis after the event, MISO determined that 91.2% of the scheduling instructions sent to Load Modifying Resources were met.[45]

In August and September 2023, the ERCOT region expected operating reserves to be low and requested that the ERCOT region conserve electricity on numerous days.[46] During the September event, conditions in ERCOT eventually led to an Energy Emergency Alert Level 2 (EEA 2) to ensure reliable operations.[47] To continue reliable operations, ERCOT used demand response to lower electric demand in the ERCOT region.[48]

---

https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

[44] *Id.* at 4 & 12.

[45] MISO Resource Adequacy Subcommittee, *Load Modifying Resource (LMR) Penalty Assessment: December 23, 2022 Max Gen Event*, (July 2023), https://cdn.misoenergy.org/20230711-12%20RASC%20Supplemental%20December%20Event%20Penalty%20Assessment629481.pdf.

[46] ERCOT, News Release, *ERCOT Expects Tight Grid Conditions Later Today, Requests Conservation* (August 24, 2023), https://www.ercot.com/news/release/2023-09-06-ercot-expects-tight; ERCOT, News Release, *ERCOT Expects Tight Grid Conditions, Requests Conservation Today from 6 p.m. to 9 p.m. CT* (September 6, 2023), https://www.ercot.com/news/release/2023-09-06-ercot-expects-tight.

[47] ERCOT, News Release, ERCOT Has Initiated Energy Emergency Alert Level 2 (EEA 2), Conservation is Critical (September 6, 2023), https://www.ercot.com/news/release/2023-09-06-ercot-has-initiated.

[48] ERCOT, News Release, ERCOT Has Exited Emergency Operations, Returned to Normal Grid Conditions. No Grid-related Outages Were Necessary. (September 6, 2023), https://www.ercot.com/news/release/2023-09-06-ercot-has-exited.

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

In May 2023, The Brattle Group published a report that estimated the net cost of providing resource adequacy from a virtual power plant (VPP) as compared to the net cost of resource adequacy from a gas peaking resource or a utility-scale battery resource.[49] Brattle modeled the performance of a 400 MW VPP composed of aggregations of smart thermostats, smart water heaters, electric vehicle (EV) managed charging, and behind-the-meter batteries operated to provide demand response to reduce or shift load.[50] Brattle found that a VPP offering demand response could provide the same resource adequacy benefits as a gas peaking resource or a utility-scale battery resource at 40% to 60% of the cost, before considering additional benefits that a VPP can provide such as energy and ancillary services cost savings, emissions reductions, transmission and distribution investment deferrals, and avoided outages associated with using DERs as backup generation.[51]

In May 2023, the California Energy Commission (CEC) adopted a goal to develop 7,000 MW of load flexibility by 2030 to meet the state's decarbonization policy goals and facilitate the smarter use of clean energy resources.[52] California Senate Bill 846 required the CEC to develop a statewide goal for load shifting to reduce net peak electrical demand, and the CEC determined that a 7,000 MW statewide load-flexibility goal was aspirational but achievable with robust policy support.[53] The CEC classifies load flexibility resources into three categories:

- Load-Modifying – This category includes demand flexibility that directly affects load forecast and resource procurement requirements for load-serving entities (LSEs). The most common type of load-modifying flexibility comes from time-varying rates, although some LSEs are also

---

[49] Ryan Hledik & Kate Peters, Brattle, Real Reliability: The Value of Virtual Power (May 2023), https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf.

[50] *Id.* at 12-14. The researchers modeled the performance of the VPP in an illustrative utility system, with a 3,700 MW gross peak demand and a net load profile that required resource adequacy performance in many hours during both the summer and winter seasons.

[51] *Id.* at 5, 17 & 26.

[52] California Energy Commission, News Releases, *California Adopts Goal to Make More Electricity Available Through Smarter Use* (May 31, 2023), https://www.energy.ca.gov/news/2023-05/california-adopts-goal-make-more-electricity-available-through-smarter-use.

[53] Ingrid Neumann & Erik Lyon, California Energy Commission, Senate Bill 846 Load-Shift Goal Report 2-3 (May 2023), https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report.

experimenting with more direct interventions including a behind-the-meter battery storage pilot program.[54]

- Resource Planning and Procurement – This category includes load flexibility resources that either contribute to meeting resource adequacy requirements or reduce resource adequacy requirements. This includes resources participating as supply-side demand response resources in CAISO as either economic demand response or reliability demand response (with an economic bidding option).[55]

- Incremental and Emergency – This category includes load flexibility resources that are intended to increase resource availability during extreme events that may be difficult to adequately account for in planning. This includes resources participating in the Emergency Load Reduction Program and the Demand Side Grid Support Program, which can be activated during a grid emergency or to prevent a grid emergency under conditions of high grid need.[56] However, unlike the resource planning and procurement category, these load flexibility resources do not contribute to the resource adequacy requirements that load-serving entities must meet.

CEC estimates that the state currently has 3,100 MW to 3,600 MW of load flexibility resources and proposes a 2030 goal to reach 7,000 MW. Approximately 3,000 MW of this would come from load-modifying resources and approximately 4,000 MW would come from a combination of resource planning and procurement resources, and incremental and emergency resources.[57]

Since 2018, the Organization of MISO States (OMS) has conducted an annual survey of LSEs in the MISO footprint focused on issues related to the deployment of DERs. The 2023 OMS Survey found that the amount of DERs continue to grow in MISO with a significant increase in residential customer DERs.[58] The OMS Survey found that solar and demand response are the most common DERs in MISO.[59] OMS and MISO also jointly conduct an annual, voluntary survey to assess resource adequacy.[60] The OMS and MISO Study found that committed capacity from all resources declined over the survey window with potential resource deficits in the region starting in planning year 2025/2026, which runs from June 1, 2024,

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

[55] *Id.* at 2.

[56] *Id.* at 2.

[57] *Id.* at 4.

[58] Organization of MISO States, 2023 OMS DER Survey Results 2 (September 2023), https://www.misostates.org/images/stories/Other_Projects/2023_DER_Survey_Results_Public.pdf.

[59] *Id.* at 6.

[60] The 2023 report has approximately 90% participation from existing generation capacity. *See* 2023 OMS-MISO Survey Results at 2 (July 2023), https://cdn.misoenergy.org/20230714%20OMS%20MISO%20Survey%20Results%20Presentation629607.pdf.

through May 31, 2025. OMS and MISO note in their analysis of the survey results that external factors could affect the projected deficits, and that one potential mitigating factor was sustained MISO market responses to recent planning resource auctions, including the registration of additional load-modifying resources in the future.[61]

[61] *Id*. at 5.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter presents regional information on retail demand response[62] and dynamic pricing[63] programs based on EIA data. From 2018 to 2022, nationwide enrollment in dynamic pricing programs has increased by more than 5.4 million customers, or 58.8%, while enrollment in retail demand response programs increased by over 740,000 customers, or 7.6%. This suggests that utilities continue to increase enrollments in programs designed to leverage advanced meter investment and customer participation in cost-saving programs. This chapter also summarizes recent federal, regional, state, and industry actions and developments related to demand response. As noted earlier in the report, FERC staff does not independently verify the accuracy of EIA data, but rather reports the data as they were reported by EIA.

Enrollment in Retail Demand Response and Dynamic Pricing

Table 5-1 shows customer enrollment in retail incentive-based demand response programs for each of the nine Census Divisions in 2020 and 2021. From 2020 to 2021, customer enrollment in retail incentive-based demand response programs in the United States decreased by approximately 1.2 million customers, or 10.1%, from approximately 11.7 million customers to approximately 10.5 million customers. This decline can be attributed to enrollment declines reported by utilities in the East South Central, Middle Atlantic, Pacific, South Atlantic, and West North Central Census Divisions. While the number of customers enrolled in retail demand response programs declined nationwide, the East North Central, Mountain, New England, and West South Central Census Divisions experienced small aggregate increases from 2020 to 2021.

[62] Demand-side management (DSM) programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. DSM 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 Annual Electric Power Industry Report (Short Form) Instructions* at 3, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; EIA, *Form EIA-861 Annual Electric Power Industry Report 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.

[63] 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. They include time-of-use prices, as well as real-time pricing, variable peak pricing, critical peak pricing, and critical peak rebate programs. *See* EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3-4, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; and EIA, *Form EIA-861 Annual Electric Power Industry Report Instructions,* Schedule 6 Part C, https://www.eia.gov/survey/form/eia_861/instructions.pdf.

Table 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2020 and 2021)

Census Division	Enrollment in Retail Demand Response Programs		Year-over-Year Change	
	2020	2021	Customers	%
East North Central	1,341,782	1,356,961	15,179	1.1%
East South Central	200,229	199,657	-572	-0.3%
Middle Atlantic	467,095	146,662	-320,433	-68.6%
Mountain	1,233,417	1,302,405	68,988	5.6%
New England	57,486	63,140	5,654	9.8%
Pacific	1,706,329	793,563	-912,766	-53.5%
South Atlantic	4,497,326	4,465,363	-31,963	-0.7%
West North Central	1,262,248	1,260,090	-2,158	-0.2%
West South Central	899,751	904,743	4,992	0.6%
Total	**11,665,663**	**10,492,584**	**-1,173,079**	**-10.1%**

Source: 2021 Form EIA-861 Utility_Data_2021 data file, 2021 Form EIA-861 Demand_Response_2021 data file, 2020 Form EIA-861 Utility_Data_2020 data file, and 2020 Form EIA-861 Demand_Response_2020 data file.

Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data.

Figure 5-1 below shows changes in customer enrollment in retail incentive-based demand response programs in each Census Division from 2018 to 2021. Over this period, the trend in customer enrollment in such programs varied across Census Divisions. The New England, West South Central, Mountain, East North Central, and South Atlantic Census Divisions experienced an upward trend in customer enrollment in retail incentive-based demand response programs from 2018 to 2021. In contrast, the Middle Atlantic and Pacific Census Divisions experienced declines in customer enrollment. Customer enrollment in retail incentive-based demand response programs remained relatively stable in the East South Central and West North Central Census Divisions over that same time. In 2021, utilities in the South Atlantic Census Division reported the greatest number of customers enrolled in retail incentive-based demand response programs, with approximately 4.5 million customers enrolled.

As discussed above, five of the nine Census Divisions experienced decreases in customer enrollment in retail incentive-based demand response programs from 2020 to 2021. The Pacific, Middle Atlantic, and South Atlantic Census Divisions experienced the largest aggregate decreases, with utilities in those Census Divisions reporting approximately 913,000, 320,000 and 32,000 fewer customers enrolled in 2021 compared to 2020, respectively. Notably, the decrease in the Pacific Census Division can be mainly attributed to San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company, which reported approximately 881,000, 30,000, and 11,000 fewer customers enrolled in 2021. The decrease in the Middle Atlantic Census Division was mainly due to utilities in Pennsylvania reporting in aggregate approximately 301,000 fewer customers enrolled in retail demand response programs. Finally, in the South Atlantic Census Division, Potomac Electric Power Company in Maryland, Delmarva Power in Delaware, and Delmarva Power in Maryland, respectively, reported approximately 56,000, 46,000, and 27,000 fewer customers enrolled.

From 2020 to 2021, the Mountain Census Division experienced the largest increase in customer enrollment in retail incentive-based demand response programs. In aggregate, utilities in the Mountain Census Division reported approximately 69,000 additional customer enrollments in 2021 compared to 2020. Notably, Arizona Public Service Company reported approximately 39,000 additional customers enrolled in retail demand response programs. Utilities in other Census Divisions also experienced significant increases in enrollment in retail demand response programs. For example, Baltimore Gas and Electric Company in the South Atlantic Census Division, Consumers Energy Company Electric Company in the East North Central Census Division, and Portland General Electric Company in the Pacific Census Division reported approximately 93,000, 46,000 and 40,000 additional customers enrolled in retail incentive-based demand response programs, respectively.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2018 – 2020)

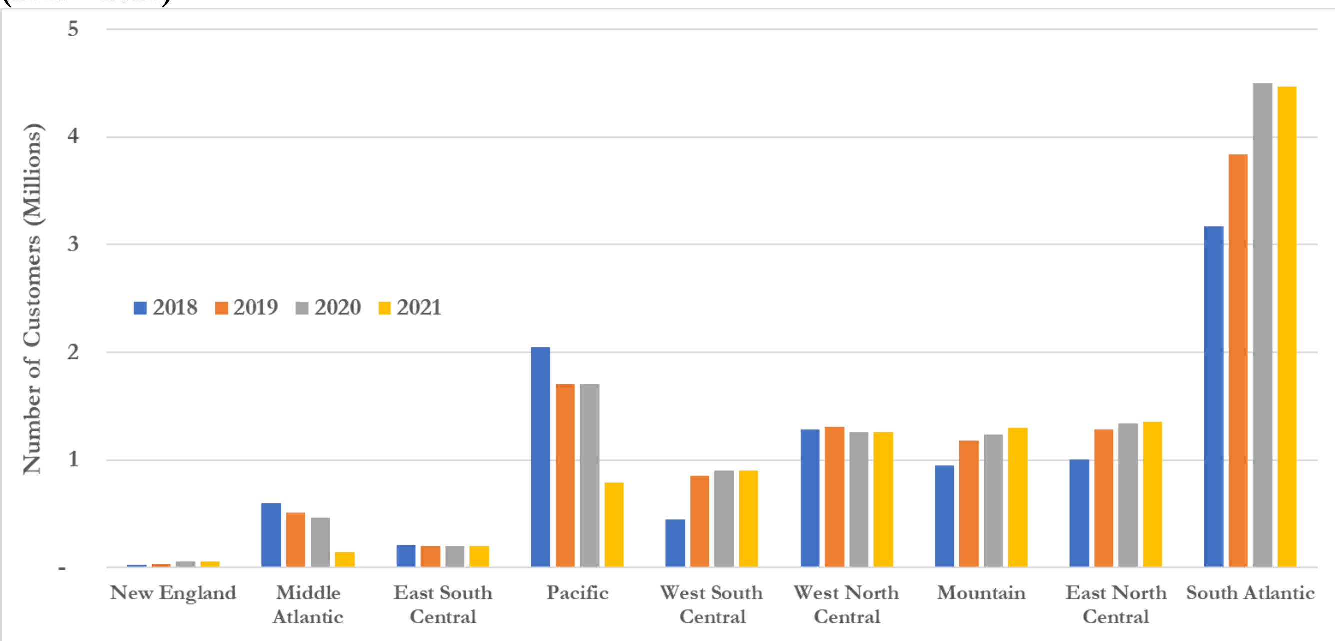


Table 5-2 below shows customer enrollment in retail dynamic pricing programs for each of the nine Census Divisions in 2020 and 2021. From 2020 to 2021, customer enrollment in retail dynamic pricing programs in the United States increased by approximately 2.4 million customers, or 20.1%. Four Census Divisions experienced aggregate increases in customer enrollment. The Pacific Census Division experienced the largest aggregate increase, with utilities reporting approximately 2.9 million additional customers enrolled in retail dynamic pricing programs in 2021. The significant annual enrollment increase in the Pacific Census Division coincides with the California Public Utility Commission's (California PUC's) 2015 decision requiring utilities to transition customers to default time-of-use (TOU) rates.[64] Utilities in the Middle

[64] *Phase I Decision Addressing Timing of Transition to Residential Default Time-of-Use Rates*, Decision No. D.18-05-011 (California PUC May 2018), https://docs.cpuc.ca.gov/publisheddocs/published/g000/m214/k512/214512974.pdf. *See also, Phase IIB Decision Addressing Residential Default Time-of-Use Rates Design Proposals and Transition Implementation,* Decision

Atlantic, Mountain, and West North Central Census Divisions also reported more customers enrolled in retail dynamic pricing programs in 2021 compared to 2020. While enrollment in retail dynamic pricing programs increased nationwide, the East North Central, East South Central, New England, South Atlantic, and West South Central Census Divisions experienced aggregate decreases in customer enrollment. Utilities in the East North Central Census Division reported approximately 636,000 fewer customers enrolled in retail dynamic pricing programs in 2021, which represented the largest decrease among Census Divisions.

Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2020 and 2021)

Census Division	Enrollment in Dynamic Pricing Programs		Year-over-Year Change	
	2020	2021	Customers	%
East North Central	1,499,293	863,185	-636,108	-42.4%
East South Central	75,039	72,446	-2,593	-3.5%
Middle Atlantic	228,079	259,426	31,347	13.7%
Mountain	1,289,443	1,377,686	88,243	6.8%
New England	139,130	138,943	-187	-0.1%
Pacific	4,717,696	7,665,830	2,948,134	62.5%
South Atlantic	2,429,467	2,397,528	-31,939	-1.3%
West North Central	189,341	261,577	72,236	38.2%
West South Central	1,627,519	1,606,630	-20,889	-1.3%
Total	**12,195,007**	**14,643,251**	**2,448,244**	**20.1%**

Source: 2021 Form EIA-861 Dynamic_Pricing_2021 data file, 2021 Form EIA-861 Utility_Data_2021 data file, 2020 Form EIA-861 Dynamic_Pricing_2020 data file, and 2020 Form EIA-861 Utility_Data_2020 data file.

Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data.

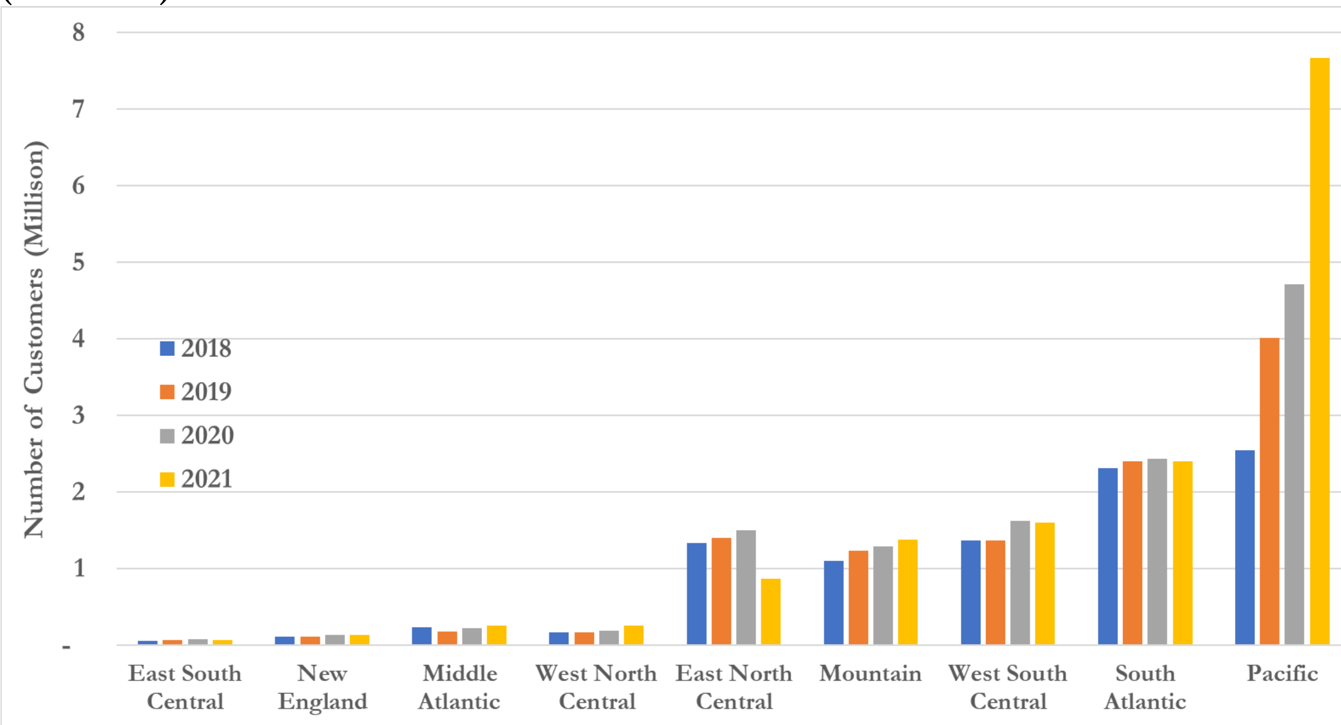
Turning to retail dynamic pricing programs, Figure 5-2 below shows changes in customer enrollment in those programs in each Census Division from 2018 through 2021. Over this period, except for East North Central between 2020 and 2021, customer enrollment in retail dynamic pricing programs showed an upward trend across all Census Divisions. Utilities in the Pacific Census Division continued to report the largest aggregate number of customers enrolled in retail dynamic pricing program, with approximately 7.7 million customers enrolled in 2021. Notably, Pacific Gas & Electric Company and Southern California Edison Company reported approximately 1.5 million and 387,000 more customers enrolled in retail dynamic pricing programs in 2021 compared to 2020, respectively. Utilities in other Census Divisions also experienced significant increases in customer enrollment from 2020 to 2021. For example, Union Electric Company in the West North Central Census Division, Arizona Public Service Company in the Mountain Census Division, and Commonwealth Edison Company in the East North Central Census Division reported

---

No. 19-07-004 (California PUC July 2019), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M309/K843/309843509.PDF.

approximately 64,000, 45,000, and 35,000 additional customers, respectively, enrolled in retail dynamic pricing programs in 2021.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 – 2021)



FERC Demand Response Orders and Activities

ISO-NE Order No. 2222 Compliance Filing (ER22-983)

In February 2022, ISO-NE submitted proposed tariff revisions to comply with the Commission's Order Nos. 2222.[65] As relevant to this report, ISO-NE proposed to allow DER Aggregators[66] of demand response resources to use either ISO-NE's existing Demand Response Resource participation model or a newly proposed DER-specific model, the Demand Response Distributed Energy Resource Aggregation (DRDERA) model. ISO-NE explained that the DRDERA model enables demand response DERs to aggregate with non-demand response DERs, as required by Order Nos. 2222 and 2222-B.[67] The model is

---

[65] ISO-NE, Transmittal, Docket No. ER22-983-000 (filed Feb. 2, 2022) (ISO-NE Transmittal Letter).

[66] The Commission defined a distributed energy resource aggregator in Order No. 2222 as "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy, an/or ancillary service markets of the regional transmission organizations and/or independent system operators." *See* Final Rule, Order No. 2222, 18 CFR Part 35, 172 FERC ¶ 61,247, at P 18 (2020).

[67] ISO-NE Transmittal Letter at 16.

designed to allow such aggregations of DERs with both demand reduction capability and energy injection capability to provide energy in the form of demand reduction, and to provide energy injections or withdrawal energy and be billed or settled at the appropriate locational marginal price (LMP).

In March 2023, the Commission issued an order accepting ISO-NE's filing in part, subject to further compliance filings. In that order, the Commission found that ISO-NE's proposed DRDERA participation model for resources to provide energy and ancillary services accommodates the physical and operational characteristics of heterogeneous DER Aggregators that can provide energy injection and demand response.[68] In November 2023, the Commission accepted ISO-NE's Third Compliance Filing subject to further compliance, which, among other things, addressed ISO-NE's proposed revisions related to metering and telemetry system requirements.[69]

MISO Order No. 2222 Compliance Filing (ER22-1640)

On April 14, 2022, and as amended on October 11, 2022, MISO submitted to the Commission proposed tariff revisions to comply with Order No. 2222.[70] On October 10, 2023, the Commission found that MISO partially complied with Order No. 2222's requirements and ordered MISO to submit further compliance filings within 60 days.[71] As relevant to this report, the Commission found that MISO had complied with Order No. 2222's requirement to allow any type of DER technology in an aggregation to participate in their the market.[72] The Commission also found that MISO had complied with the Order No. 2222 directive to allow for heterogeneous aggregations of injecting and demand-curtailing resources in MISO's market.[73] In addition, the Commission found that MISO's metering proposal complied with Order No. 2222 because DERAs did not need separate meters for their load reduction portions and that portion would be settled using existing settlement rules for demand response.[74]

NYISO DER and Aggregation Participation Model (ER23-2040)

[68] *ISO-New England,* 182 FERC ¶ 61,137, at P 65 (2023). The Commission issued an order on rehearing on October 6, 2023, *See ISO-New England*, 185 FERC ¶ 61,021 (2023).

[69] *ISO-New England,* 185 FERC ¶ 61,095, at P 2, 6 (2023).

[70] *Midcontinent Independent System Operator, Inc.*, 185 FERC ¶ 61,011 (2023).

[71] *Id.* at P 17.

[72] *Id.* at P 69.

[73] *Id.* at P 70.

[74] *Id.* at P 210.

On June 1, 2023, NYISO filed proposed revisions to its tariff to modify its DER and Aggregation participation model that the Commission first accepted in January 2020.[75] NYISO proposed several revisions to market rules applicable to DERs and Aggregations, including changes to establish a minimum capability of 10 kW for individual DERs participating in an Aggregation, clarify metering requirements for Aggregations, and modify the methodology used to calculate load baselines for demand side resources participating in DER Aggregations.[76] NYISO also proposed to implement a previously-approved phase out of its existing economic-based demand response programs and a 12-month transition period for the resources participating in those programs to switch to the DER and Aggregation participation model. On July 18, 2023, Commission staff issued a letter informing NYISO that its filing was deficient and requesting additional information needed to process the filing.[77] As of the publication of this report, this filing is still pending before the Commission.

PJM Order No. 2222 Compliance Filing (ER22-962)

PJM, in February 2022 and, as amended in July 2022, submitted proposed revisions to its Tariff, Operating Agreement, and its Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (RAA) to comply with the Commission's Order Nos. 2222-A and 2222-B.[78] As relevant to this report, PJM proposed tariff language establishing a DER Aggregation Participation Model that would allow demand response resources to participate in the PJM energy, capacity, and ancillary service markets either under a heterogeneous DER Aggregation Participation Model (where demand response DERs may be aggregated with other DERs) or a homogeneous Demand Response Resource Model (aggregated demand response only).[79] In March 2023, the Commission accepted PJM's revisions, subject to additional compliance filings by PJM.[80] The Commission found that PJM had partially complied with the metering and telemetry requirements of Order No. 2222 because its proposed revisions did not contain deadlines for meter data submissions for settlements. The Commission directed PJM to submit a further compliance filing with tariff revisions to address this issue.[81]

---

[75] N.Y. Indep. Sys. Operator, Inc., Transmittal, Docket No. ER23-2040-000 (filed June 1, 2023). This participation model has also been modified through separate filings NYISO submitted to comply with Order No. 2222. *See N.Y. Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,033 (2020).

[76] *Id.* at 5-16.

[77] N.Y. Indep. Sys. Operator, Inc., Deficiency Letter, Docket No. ER23-2040-000 (filed July 18, 2023).

[78] *PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,143, at P 1 (2023).

[79] *Id.* at P 4, 52, 58, 62, 96.

[80] *Id.* at P 1. The Commission issued an order on rehearing on July 11, 2023, *See PJM*, 184 FERC ¶ 61,019 (2023).

[81] *Id.* at P 248-249.

Commission Enforcement Activity

On May 22, 2023, the Commission issued an order approving a Stipulation and Consent Agreement that resolved the Commission's Office of Enforcement's investigation of a demand response provider, OhmConnect, Inc. (Ohm), and whether Ohm violated a provision of CAISO's Tariff.[82] The Office of Enforcement alleged that Ohm made numerous bids into CAISO's day-ahead energy market that exceeded the registered metered load of its customers in the first six months of 2018 and received Resource Adequacy Availability Incentive Mechanism payments totaling $8,906 in May and June of 2018 that it would have not received if it had made accurate bids.[83] The Office of Enforcement determined that Ohm violated Section 37.3.1.1. of CAISO's Tariff that requires market participants to make bids that they reasonably expect to be able to fulfill because Ohm's bids exceeded the registered metered load of all its customers.[84] The Commission directed Ohm and Ohm agreed to: (1) pay a civil penalty of $141,094 to the United States Treasury; (2) disgorge $8,906 to CAISO; and (3) submit to compliance monitoring as detailed in the Stipulation and Consent Agreement.[85]

Other Federal Demand Response Activities

Department of Defense

The U.S. Department of Defense (DOD) Defense Logistics Agency (DLA) provides DOE and other federal agencies with a variety of services. In particular, the DLA Energy Installation Energy Division provides acquisition support for facility energy commodities and services, and serves as coordinator and facilitator for DOD's participation in electricity demand response programs.[86] In fiscal year 2022, the DLA facilitated the participation of 45 federal installations in 12 states and the District of Columbia in demand response programs. These installations collectively represent approximately 92 MW of enrolled resources, and as of the date of its annual report, DLA states that participation in the programs resulted in approximately $2.23 million in savings in fiscal year 2022.[87]

---

[82] *OhmConnect, Inc.*, 183 FERC ¶ 61,136, at P 1 (2023); *See also Leapfrog Power, Inc.*, 183 FERC ¶ 61,137 (2023) (approving an issuance of a penalty and a settlement between a demand response provider, Leapfrog Power, Inc., and Enforcement on the same alleged violations).

[83] *OhmConnect, Inc.*, 183 FERC ¶ 61,136, at P 2.

[84] *Id.*

[85] *Id.*

[86] Defense Logistics Agency, *Defense Logistics Agency Energy Fiscal Year 2022 Fact Book* at 17, https://www.dla.mil/Portals/104/Documents/Energy/Publications/DLAEnergyFactBook2022_2.pdf?.

[87] *Id.* at 58.

Department of Energy

On April 25, 2023, DOE announced the Grid Modernization Initiative (GMI) lab call, a $38 million funding opportunity for National Laboratories to advance research and development for building and modernizing a reliable grid.[88] The GMI lab call expects to award in the following five topic areas: (1) power and controls electronics; (2) cybersecurity for architectures, standards, and practices; (3) quantum facilities for computing, sensing, and security; (4) equitable system operation and planning; and (5) climate impact on energy resources.[89] Specifically, the GMI lab call expresses interest in proposals advancing and evaluating medium-voltage electronics and the associated medium-voltage sub-system and DER interfaces[90], as well as proposals assessing and/or developing cybersecurity architectures and practices focusing on standards for electric vehicle supply equipment (EVSE), standards for DER systems, and communication architecture among many other interests.[91]

On August 7, 2023, DOE announced $46 million in funding awards for 29 projects across 15 states through the Buildings Energy Efficiency Frontiers and Innovative Technologies (BENEFIT) funding opportunity.[92] The BENEFIT program focuses on supporting cost-effective solutions to electrify buildings while also improving their energy efficiency and demand flexibility. Several of the projects receiving funding involve thermal energy storage technologies for use in Heating, Ventilation & Air Conditioning (HVAC) applications. For example, a project team at the University of Wisconsin Madison was awarded $2.5 million to develop a plug-and-play multi-split HVAC system for heating and cooling that incorporates modular thermal storage units that can reduce electricity consumption by up to 50% for four-hour intervals during periods of peak demand.[93]

Developments and Issues in Demand Response

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

---

[88] Department of Energy, *DOE Announces $38 Million to Modernize the Electricity* Grid (Apr. 25, 2023), https://www.energy.gov/gmi/articles/doe-announces-38-million-modernize-electricity-grid.

[89] *Id.*

[90] Medium-voltage electrical interfaces are defined as 4.16 kV-34.5 kV, *See Id.* at 6.

[91] Department of Energy, *Grid Modernization Lab Call 2023* (Apr. 2023), at 7-8 and 10-11, https://www.energy.gov/sites/default/files/2023-04/2023-gmi-lab-call_updated.pdf.

[92] Department of Energy, *DOE Announces $46 Million to Boost Energy Efficiency and Slash Emissions in Residential and Commercial Buildings* (August 7, 2023), https://www.energy.gov/articles/doe-announces-46-million-boost-energy-efficiency-and-slash-emissions-residential-and.

[93] Department of Energy, *Meet DOE's Newest Research Projects from BENEFIT 22-23* (August 7, 2023), https://www.energy.gov/eere/buildings/articles/meet-does-newest-research-projects-benefit-22-23.

California. The California PUC commissioned a study to determine the impacts and costs of successfully achieving California's electrification and decarbonation goals while maintaining reliability and ensuring equity and affordability of electricity services.[94] The study provides preliminary estimates of the scope and scale of the potential impacts on the state's electric distribution system that could result from widespread transportation electrification and solar photovoltaic penetration through 2035. The study assessed several scenarios with varying assumptions, including the penetration of transportation electrification and whether behind the meter tariffs remain the same or are modified.[95] It found that TOU rates and flexible load management strategies could help to cost-effectively transition the distribution grid to accommodate California's electrification and decarbonization goals.[96] The study suggests that further studying how DERs and other load management techniques can mitigate projected, significant capital costs for distribution grid enhancements will be critical to achieving California's electrification goals.[97] It will be followed by a more detailed Part 2 study containing utility-specific projections.

Hawaii. On October 31, 2022, the Hawaii Public Utilities Commission (Hawaii PUC) issued an order establishing an Advanced Rate Design (ARD) Implementation Framework (ARD Framework) to inform Hawaiian Electric Company's development and implementation of advanced rates.[98] The ARD Framework: (1) identifies the overarching goals, guiding principles, and desired end-state of ARD for Hawaiian Electric Company; (2) establishes the foundational elements of new TOU rates for residential, general service non-demand, and general service demand customer classes; and (3) identifies the staged approach that ARD implementation will require.[99] Hawaiian Electric Company will implement several TOU rate elements including TOU energy charges applied in three daily periods—daytime, evening peak, and overnight—and price ratios of 1:2:3 for the daytime, overnight and peak periods, respectively.[100] Customers must have AMI installed for at least six months to be eligible for TOU enrollment.[101]

Indiana. On November 9, 2022, Duke Energy Indiana filed a petition with the Indiana Utility Regulatory Commission (Indiana URC) for approval of its Demand Side Management and Energy Efficiency Plan for

---

[94] Kevala, Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates ES-1 (May 2023), https://uploads-ssl.webflow.com/62a236e9692c48cff36898da/6462917ab8a790b6b85f5fbb_CPUC%20Kevala%20EIS%20Part%201.pdf.

[95] *Id.* at 10.

[96] *Id.* at ES-9.

[97] *Id.*

[98] *In the Matter of Instituting a Proceeding to Investigate Distributed Energy Resource Policies Pertaining to The Hawaiian Electric Companies*, Docket No. 2019-0323 (Hawaii PUC Oct. 31, 2022) at 1-2, https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22K01B04701A00323.

[99] *Id.* at 2.

[100] *Id.* at 25.

[101] *Id.* at 136.

2024-2026 and to recover the costs associated with the program and any reasonable lost revenue and financial incentives.[102] In the petition, Duke Energy proposed to continue its current demand response programs and to launch a new, non-residential demand response program.[103] Duke Energy Indiana explained that it employed an independent third-party to continue to evaluate, measure, and verify the results of the programs, consistent with its procedures.[104]

Maryland. The Potomac Edison Company filed the Revised Electric Vehicle Charging Infrastructure Pilot Program on February 22, 2023.[105] On April 5, 2023, the Maryland Public Service Commission issued an order approving Potomac Edison Company's proposed voluntary EV-only TOU rate for eligible residential customers to replace its current EV charger off-peak credit tariff rate, effective May 15, 2023. Customers enrolled in the EV-only TOU rate will see an incremental credit of 2¢/kWh off the electric supply charge for EV charging during off-peak hours, and an incremental charge of 2¢/kWh added to the electric supply charge for EV charging during on-peak hours.[106]

Michigan. On December 21, 2022, the Michigan Public Service Commission (Michigan PSC) issued an order that partially lifted an existing ban that prohibited Michigan retail electric customers from bidding demand response (either individually or through aggregators) into RTO wholesale markets.[107] The Michigan PSC found that it was appropriate to remove the ban and allow commercial and industrial customers with over 1 MW of load to participate in wholesale markets. However, the Michigan PSC also decided to keep the ban in place for residential customers, noting that it would reconsider that decision as it gains more experience with demand response resource aggregation of retail electric customers.[108] In its decision, the

[102] *Petition Of Duke Energy Indiana, LLC for Approval Of: (1) Its Demand Side Management and Energy Efficiency Plan for 2024 -2026, Including Energy Efficiency Programs and Demand Response Programs; (2) Accounting and Ratemaking Treatment, Including Timely Recovery of Associated Program Costs, Including Reasonable Lost Revenues and Financial Incentives, and Authority to Defer Costs; and (3) New Standard Contract Rider 74, Load Control Adjustment*, Docket No. 45803 (Indiana URC November 9, 2022) at 1, https://iurc.portal.in.gov/docketed-case-details/?id=716e922d-4360-ed11-9562-001dd8070a7e.

[103] *Id.* at 4.

[104] *Id.* at 4-5.

[105] *Letter Order to PE accepting Revised Electric Vehicle Charging Infrastructure Pilot Program*, Docket No. 9478 (ML 302256) (Maryland PSC April 5, 2023), https://webpsc.psc.state.md.us/DMS/case/9478.

[106] Potomac Edison, Revised Electric Vehicle Charging Infrastructure Pilot Plan, Case No. 9478 (ML 301441) (Maryland. PSC February 22, 2023), at 3-6,), https://webpsc.psc.state.md.us/DMS/case/9478.

[107] In *The Matter, on the Commission's Own Motion, to Address Outstanding Issues Regarding Demand Response Aggregation for Alternative Electric Supplier Load*, Docket No. U-20348 (Michigan PSC December 21, 2022) at 31-32, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000005iClRAAU.

[108] *Id.* at 34-36.

Michigan PSC noted, among other considerations, arguments that the tight capacity market within MISO's footprint calls for expanding capacity resources like demand response.[109]

Minnesota. On August 24, 2023, Minnesota Public Utility Commission (Minnesota PUC) Staff issued Staff Briefing Papers that summarized the activities in their docket on the potential role of Third-Party Aggregation of Retail Customers and next steps the Minnesota PUC could take. The Staff Briefing Papers explained that on March 15, 2022, the Minnesota PUC partially approved Northern States Power Company's February 1, 2021, petition to establish four load-flexibility pilot programs (March Order).[110] One pilot uses commercial customers to examine options to increase customer participation in demand response programs.[111] As a part of approving this pilot, the Minnesota PUC required that third-party aggregators of retail customers be included in the second part of the pilot.[112] The March Order explained that the Minnesota PUC was not broadly authorizing third-party aggregation of demand response in Minnesota with this pilot, but was allowing its Executive Secretary to open an inquiry into whether: (1) to allow third-party aggregation of retail customers to bid demand response into organized markets; (2) to require the creation of tariffs by the rate-regulated electric companies to allow third-party aggregators to participate in utility-run demand response programs; (3) to verify or certify demand response aggregators or DERs before they are permitted to operate; and (4) to require additional consumer protections if demand response aggregators are allowed.[113] On August 24, 2023, the Minnesota PUC voted to table the discussion for further exploration.[114]

Missouri. On December 8, 2022, the Missouri Public Service Commission (Missouri PSC), as part of a broader rate case filed on January 7, 2022 by Evergy Metro, Inc. and Evergy Missouri West, Inc.

---

[109] *Id.* at 31.

[110] *In the Matter of a Commission Investigation into the Potential Role of Third-Party Aggregation of Retail Customers*, Docket No. E999/CI-22-600 (Minnesota PUC August 24, 2023), https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7bB0F7FE89-0000-C11C-B9AB-2CE1B0A40E68%7d&documentTitle=20238-198279-01 [August 24th Minnesota PUC Staff Briefing Papers].

[111] *In the Matter of Xcel Energy's Petition for Load Flexibility Pilot Programs and Financial Incentive*, Docket No. E002/M-21-101, (Minnesota PUC March 15, 2022), at 8, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b70CD8E7F-0000-C61B-B078-53582B1BC1E4%7d&documentTitle=20223-183794-01.

[112] *Id.*

[113] August 24th Minnesota PUC Staff Briefing Papers at 3.

[114] Minnesota PUC Minutes at 3 (Minnesota PUC September 13, 2023), https://minnesotapuc.legistar.com/View.ashx?M=M&ID=1115250&GUID=8EB2C896-AC8A-4D3E-AD4D-F4486350336B.

(collectively, Evergy Missouri)[115] approved the implementation of TOU rates for Evergy Missouri.[116] The Missouri PSC found that, given Evergy Missouri's eight years of experience with and substantial investment in AMI, and numerous studies on TOU rates, setting a flat rate as the default rate would not be sufficient because it would lead to only minimal residential adoption of TOU rates.[117] The Missouri PSC found that an opt-out TOU rate is a better way to introduce a new rate design to residential customers because it leads to higher enrollment. The Missouri PSC also elected to use higher differential rates (e.g., with greater differences in on-peak and off-peak pricing) than the low price on- and off- peak pricing recommended by staff to further encourage residential adoption, but allowed several other TOU rate options.[118] The Missouri PSC also found that Missouri Staff's proposal for a default TOU rates may not be appropriate for non-residential customers without further study because their electric consumption may be driven by when customers visit their businesses (e.g. gas stations and grocery stores) and therefore a TOU rate would not affect their consumption patterns.[119]

On October 12, 2023, the Missouri PSC issued an order partially lifting its prohibition on commercial and industrial customers participating in wholesale markets via third-party aggregators of retail customers (ARCs) providing demand response.[120] In the order, the Missouri PSC explained that it opened a docket in 2021 to explore how it should respond to Order 2222 and to review its current practices in areas affected by Order 2222.[121] Based on comments the Missouri PSC received in March and April of 2021, the Missouri PSC decided to reconsider a 2010 order that temporarily prohibited ARCs from operating in Missouri.[122] In furtherance of this review, the Missouri PSC applied for and received a grant for technical assistance from the Department of Energy that was made available to help State Public Utility Commissions address

---

[115] In *the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service*, Docket No. ER-2022-0129 2022-0130 (Missouri PSC December 8, 2022) at 5, https://www.efis.psc.mo.gov/Case/Display/11386.

[116] *Id.* at 58.

[117] *Id.* at 70-71.

[118] *Id.* at 66-67.

[119] *Id.* at 76.

[120] *In the Matter of the Establishment of a Working Case Regarding FERC Order 2222 Regarding Participation of Distributed Energy Resource Aggregators in Markets Operated by Regional Transmission Organizations and Independent Systems Operators*, Docket No. EW-2021-0267 (Missouri PSC October 12, 2023), https://efis.psc.mo.gov/Document/Display/758553 [Missouri PSC ARC Order].

[121] *Id.* at 1.

[122] *Id.* at 1 & 3-4.

regulatory challenges presented by Order 2222.[123] As a part of this grant, Lawrence Berkeley National Labs (LBNL) authored a report for the Missouri PSC on how other states have regulated ARCs.[124] After the report's issuance, the Missouri PSC submitted it into the docket for stakeholder comment.[125]

Based in part on the LBNL Report and the comments it received, the Missouri PSC decided to modify the prohibition of ARCs because: (1) larger commercial and industrial customers have experience participating in wholesale electricity markets, and removing the prohibition would allow these companies to have similar opportunities in Missouri;[126] (2) it could lead to lower wholesale electricity costs, which benefits all customers;[127] (3) it can cost-effectively enhance reliability and help mitigate grid emergencies during times of serve weather;[128] (4) by allowing demand response ARCs, the Missouri PSC and utilities could obtain valuable experience in preparation of Aggregators of DER under Order 2222;[129] (5) the experience of other states, including states, like Missouri, that have vertically-integrated utilities, showed that ARCs could operate in the state without the need for additional comprehensive state-level regulations;[130] (6) wholesale demand response in MISO and SPP have continued to evolve with the establishment of procedures and regulations governing the ARCs and their operation in Missouri and the wholesale markets;[131] and (7) issues surrounding data governance and cybersecurity have been addressed by MISO, SPP, ARCs and through the implementation of Green Button functionality[132] by Missouri utilities.[133] However, the Missouri PSC found that additional work was needed before the prohibition was lifted for smaller commercial and residential

---

[123] *Id.* at 5; *See In the Matter of the Establishment of a Working Case Regarding FERC Order 2222 Regarding Participation of Distributed Energy Resource Aggregators in Markets Operated by Regional Transmission Organizations and Independent Systems Operators*, Docket No. EW-2021-0267 (Missouri PSC February 2, 2023), https://efis.psc.mo.gov/Document/Display/75740.

[124] Missouri PSC ARC Order at 5.

[125] *Id.*; *See* Sydney P Forrester, Et. Al., Lawrence Berkeley National Laboratory, Regulation of Third-Party Aggregation in the MISO and SPP Footprint (September 2023), https://efis.psc.mo.gov/Document/Display/148534.

[126] Missouri PSC ARC Order at 5-6.

[127] *Id.* at 6.

[128] *Id.*

[129] *Id.* at 6-7.

[130] *Id.* at 7.

[131] *Id.* at 7-8.

[132] The Green Button allows utility customers to access to their energy usage information in an easy and secure manner. Department of Energy, Green Button Open Energy Data, https://www.energy.gov/data/green-button/.

[133] Missouri PSC ARC Order at 8.

customers.[134] The Missouri PSC also maintained its prohibition for ARCs to enroll customers who were also enrolled in retail demand response programs, but would continue to evaluate this prohibition.[135] Therefore, the Missouri PSC found it appropriate to modify its rules to allow commercial and industrial customers with demands of 100 kilowatts (kW) or greater to participate in a wholesale market, either individually or through a third-party ARC, so long as they are not also participating in a retail demand response program.[136] The order takes effect on December 11, 2023.[137]

Virginia. On December 13, 2022, Dominion Energy, on behalf of its subsidiary Virginia Electric and Power Company, filed an application with Virginia's State Corporation Commission (Virginia SCC) to update its demand-side management plan.[138] The updated plan includes new programs and program bundles.[139] In its petition, Dominion Energy sought approval to continue its residential peak time rebate program and for a new Residential EV Telematics pilot program.[140] Dominion Energy explained that the Residential Peak Time Rebate Program is an important element of its Grid Transformation Plan and proposed to leverage it along with functionalities of its advance metering infrastructure to enable residential customers to reduce consumption during peak periods.[141] Dominion Energy also explained that the new Residential EV Telematics Pilot Program complements the existing Residential EV Demand Response program and also leverages the vehicle's onboard ability to reduce the rate of charging when signaled.[142] On August 4, 2023, the Virginia SCC issued a final order approving the proposed programs.[143]

Washington. On June 6, 2023, the Washington Utilities and Transportation Commission (Washington UTC) issued an order on Puget Sound Energy's (PSE) implementation of its Clean Energy Implementation

---

[134] *Id.* at 7.

[135] *Id.* at 5.

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

[137] *Id.* at 9.

[138] *Application of Virginia Electric and Power Company for approval of its 2022 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Docket No. PUR-2022-0021 (Virginia SCC December 13, 2022), https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/virginia/save-energy/va-dsm-application.pdf?la=en&rev=4fa5f055e9284448b9e56356f71231c1&hash=560BB5CDF888D5D78970CC6BB6A31A58.

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

[140] *Id.* at 7.

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

[142] *Id.* at 9.

[143] *Application of Virginia Electric and Power Company for approval of its 2022 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, Docket No. PUR-2022-0021 (Virginia SCC December 13, 2022) at 12-13, https://www.scc.virginia.gov/docketsearch/DOCS/7tw%2501!.PDF.

Plan as mandated by Washington's Clean Energy Transformation Act.[144] As a part of the plan, PSE set out specific procurement targets for demand response, energy efficiency, and renewables for the 2022-2025 period.[145] In approving these procurement targets, the Washington UTC placed a condition on PSE that it "increase its demand response target to include all cost effective demand response bids it received in response to its recent [request for proposal]. PSE will include expanded Direct Load Control offerings in this increased target."[146] PSE must submit a plan every four years.[147]

[144] Puget Sound Energy, Docket UE-210795 Final Order 08 (Washington UTC June 6, 2023) at 1, https://www.utc.wa.gov/casedocket/2021/210795/docsets.

[145] *Id.* at 11-12.

[146] *Id.* at 19.

[147] *Id.*

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

The deployment of customer-sited DERs and the trend towards electrification of certain transportation and building energy uses have the potential to provide grid operators with flexible loads that can be managed to meet system needs. Utilities and regulators continue to evaluate demand response, peak reduction, and critical peak pricing programs to determine how best to leverage these new types of flexible loads to cost effectively meet power system needs and accommodate changes in the resource mix and demand. This section discusses barriers that may be limiting customer participation, and efforts to address those barriers.

Rate Design and Durable Programs

A recent Lawrence Berkeley National Laboratory report looked at opportunities to use rate design, such as TOU rates, to manage the impacts of greater penetration of EVs.[148] The study found that while utilities and regulators may seek to adopt a simple rate design, they will also need to proactively manage the grid impacts of the additional electric demand caused by EVs, which may create a need for more complex rate design, e.g. encouraging off-peak charging.[149] The report found that regulators and utilities may decline to enact TOU or locational rate designs because regulators may want to promote goals other than economic efficiency, or because implementing TOU rates may be infeasible or not cost-effective due to factors such as a lack of AMI.[150] The report also found that, presently, utilities are primarily concerned with pilot programs to obtain experience with new customers, e.g. EV charging stations, and their demand patterns, but also that these pilot programs often fail to lead to the rollout of full programs.[151] The study concluded that while it will be important to consider the potential impacts of EV rate design and how it interacts with other DERs, policies, and goals, regulators and utilities should consider the frequency at which EV specific rate designs are updated to ensure that they reflect the changing grid, economic, or environmental conditions. The report notes that while retail rates are an important tool for managing EV impacts on the grid, regulators also have other tools, including incentives.[152]

---

[148] Peter Cappers. Et. Al., Lawrence Berkeley National Laboratory, *Snapshot of EV-Specific Rate Designs Among U.S. Investor-Owned Electric Utilities* V, VII (2023), https://eta-publications.lbl.gov/sites/default/files/ev_rate_snapshot_report-final-20230424.pdf.

[149] *Id.* at VIII.

[150] *Id.*

[151] *Id.*

[152] *Id.* at VIII-IX.

Lack of Dynamic Pricing

The Energy Systems Integration Group's (ESIG's) Aligning Retail Pricing and Grid Needs Task Force published a white paper in April 2023 entitled, "Rate Design for the Energy Transition: Getting the Most out of Flexible Loads on a Changing Grid."[153] The report explains that grid needs will continue to evolve as the resource mix changes and as wind, solar, and battery storage resources become the predominant new resources added to power systems across the country. The report further states that this ongoing trend is producing a shift that will continue to decrease the variable costs and increase the fixed costs of operating the power system.[154] Additionally, the report notes that technological advances and broader access to advanced metering and energy management devices has increased customers' ability to respond to dynamic retail electricity rates. It also observes that the widespread adoption of EVs will create significant new electric load with the potential to operate flexibly, but strong price signals will be needed to encourage charging during specific periods that align with overall grid needs.[155] The report argues that utilities and their regulators should go beyond thinking about retail rates primarily in the context of rate recovery, and focus on accurately compensating customer-owned DERs for the benefits they provide to the system.[156]

Market Structures Oriented Toward Accommodating Supply Side Resources

A study by the American Council for an Energy-Efficient Economy assessed whether expanded demand response and energy efficiency programs could help address Texas's reliability challenges.[157] The study notes the recent reliability challenges and the increasing electric load growth that Texas is experiencing.[158] The study found that by expanding the number of demand response and energy efficiency programs in the state, Texas could both achieve notable savings by the end of 2024 and competitively solve the reliability issues Texas is facing in the summer and winter months.[159] On August 23, 2023, the Texas Public Utility Commission (Texas PUC) announced that two virtual power plants had qualified under the Aggregate

---

[153] ESIG, *Rate Design for the Energy Transition: Getting the Most out of Flexible Loads on a Changing Grid*, https://www.esig.energy/wp-content/uploads/2023/03/ESIG-Retail-Pricing-dynamic-rates-E3-wp-2023.pdf.

[154] *Id.* at 2.

[155] *Id.* at 6.

[156] *Id.* at 15.

[157] Steve Nadel, Jennifer Amann, and Hellen Chen, American Council for an Energy-Efficient Economy, Energy Efficiency and *Demand-Response: Tools to Address Texas' Reliability Challenges: Summary* (May 2023), https://www.aceee.org/sites/default/files/pdfs/energy_efficiency_and_demand_response_-_tools_to_address_texass_energy_reliability_problems_-_encrypt.pdf.

[158] *Id.* at 1.

[159] *Id.* at 3.

Distributed Energy Resource pilot project to offer dispatchable power into the ERCOT market. The pilot project is intended to test how customer-owned, small energy devices, such as battery storage, backup generators, and controllable EV chargers can be aggregated to participate in wholesale electricity markets and strengthen grid reliability.[160]

[160] Texas PUC, Virtual Power Plants' to Provide Power to ERCOT Grid for the First Time, https://ftp.puc.texas.gov/public/puct-info/agency/resources/pubs/news/2023/PUCT_Virtual_Power_Plants_to_Provide_Power_to_ERCOT_Grid_for_the_First_Time.pdf.

Appendix: List and Map of Census Divisions

This report assesses advanced meter penetration, retail demand response, and retail dynamic pricing programs by Census Division. The current Census Divisions and states are listed below.

Division 1, New England: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont

Division 2, Middle Atlantic: New Jersey, New York, Pennsylvania

Division 3, East North Central: Indiana, Illinois, Michigan, Ohio, Wisconsin

Division 4, West North Central: Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, South Dakota

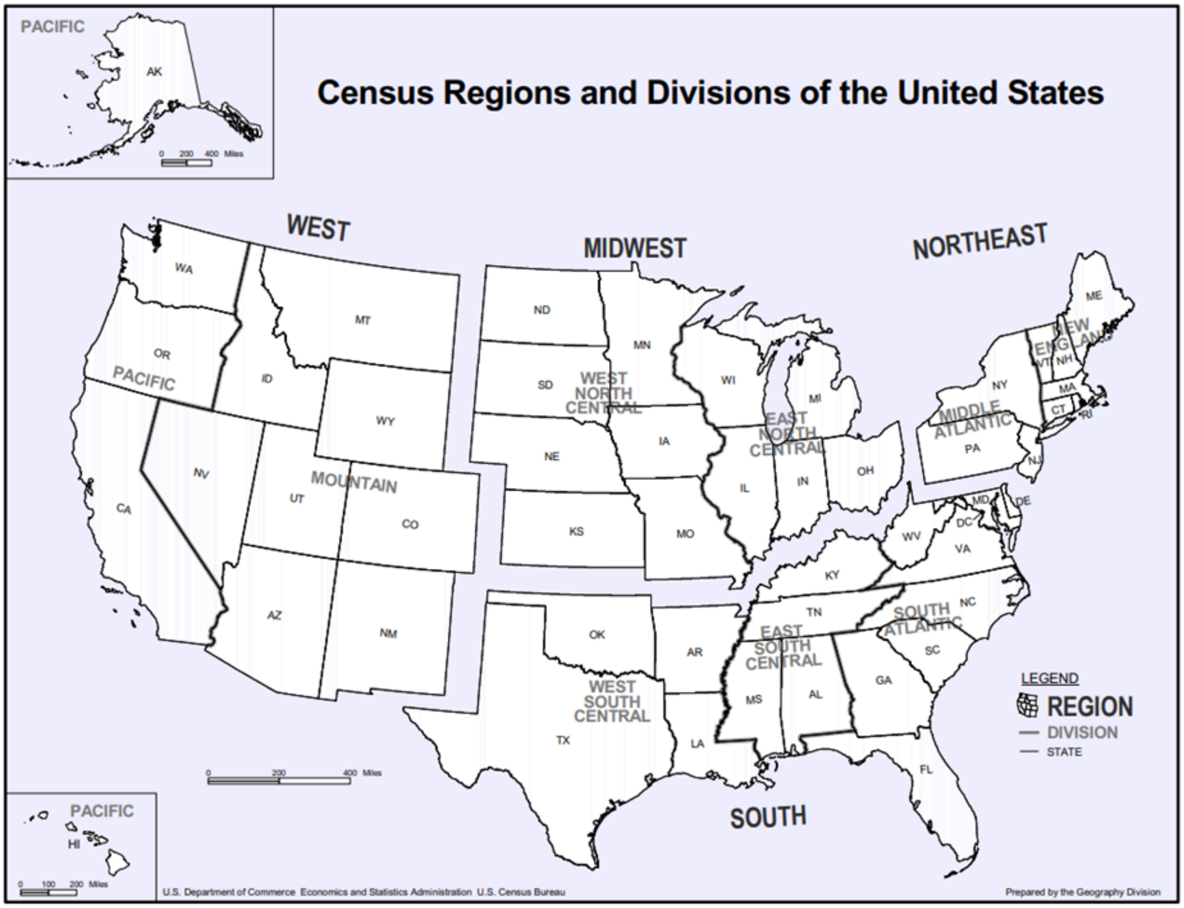
Division 5, South Atlantic: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia

Division 6, East South Central: Alabama, Kentucky, Mississippi, Tennessee

Division 7, West South Central: Arkansas, Louisiana, Oklahoma, Texas

Division 8, Mountain: Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming

Division 9, Pacific: Alaska, California, Hawaii, Oregon, Washington


Census Regions and Divisions of the United States
PACIFIC
AK
0 200 400 Miles
WEST
MIDWEST
NORTHEAST
SOUTH
PACIFIC
MOUNTAIN
WEST NORTH CENTRAL
EAST NORTH CENTRAL
NEW ENGLAND
MIDDLE ATLANTIC
SOUTH ATLANTIC
EAST SOUTH CENTRAL
WEST SOUTH CENTRAL
WA
OR
CA
NV
ID
MT
WY
UT
CO
AZ
NM
ND
SD
NE
KS
MN
IA
MO
WI
IL
MI
IN
OH
OK
TX
AR
LA
MS
AL
TN
KY
GA
FL
SC
NC
VA
WV
MD
DC
DE
PA
NJ
NY
VT
NH
ME
MA
CT
RI
0 200 400 Miles
PACIFIC
HI
0 100 200 Miles
LEGEND
REGION
DIVISION
STATE
U.S. Department of Commerce Economics and Statistics Administration U.S. Census Bureau
Prepared by the Geography Division