2021 Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

December 2021

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of Demand Response and Advanced Metering

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

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

FEDERAL ENERGY REGULATORY COMMISSION

Acknowledgements

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1. Introduction

This report is the Federal Energy Regulatory Commission (Commission) staff's sixteenth annual report on demand response and advanced metering, as required by section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005). The information presented in the report is based on publicly available data that is used to estimate demand response potential in the retail and wholesale markets.[1]

This year's report uses different regional definitions to present certain data, compared to past reports. In past reports, Commission staff reported advanced meter penetration, potential peak demand savings, retail demand response enrollment, and retail dynamic pricing enrollment totals by North American Electric Reliability Corporation (NERC) region as reported in Energy Information Administration (EIA) Form 861 data. However, in recent years, some NERC regions have changed. In May 2018, the Commission approved a joint petition to dissolve the Southwest Power Pool (SPP) Regional Entity and, beginning on July 1, 2018, transfer NERC registered entities within the SPP Regional Entity footprint to the Midwest Reliability Organization and SERC Reliability Corporation.[2] Similarly, in 2019, the Commission approved a separate joint petition to dissolve the Florida Reliability Coordinating Council as a Regional Entity and transfer NERC registered entities within the Florida Reliability Coordinating Council footprint to the SERC Reliability Corporation.[3] As a result of these changes, this year's report presents data according to the nine U.S. Census Division,[4] broken down by state in the Appendix, to meaningfully fulfill the regional reporting requirements of EPAct 2005.[5]

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[1] The latest publicly available retail data for the report is for the year 2019 while the latest publicly available wholesale data is for the year 2020.

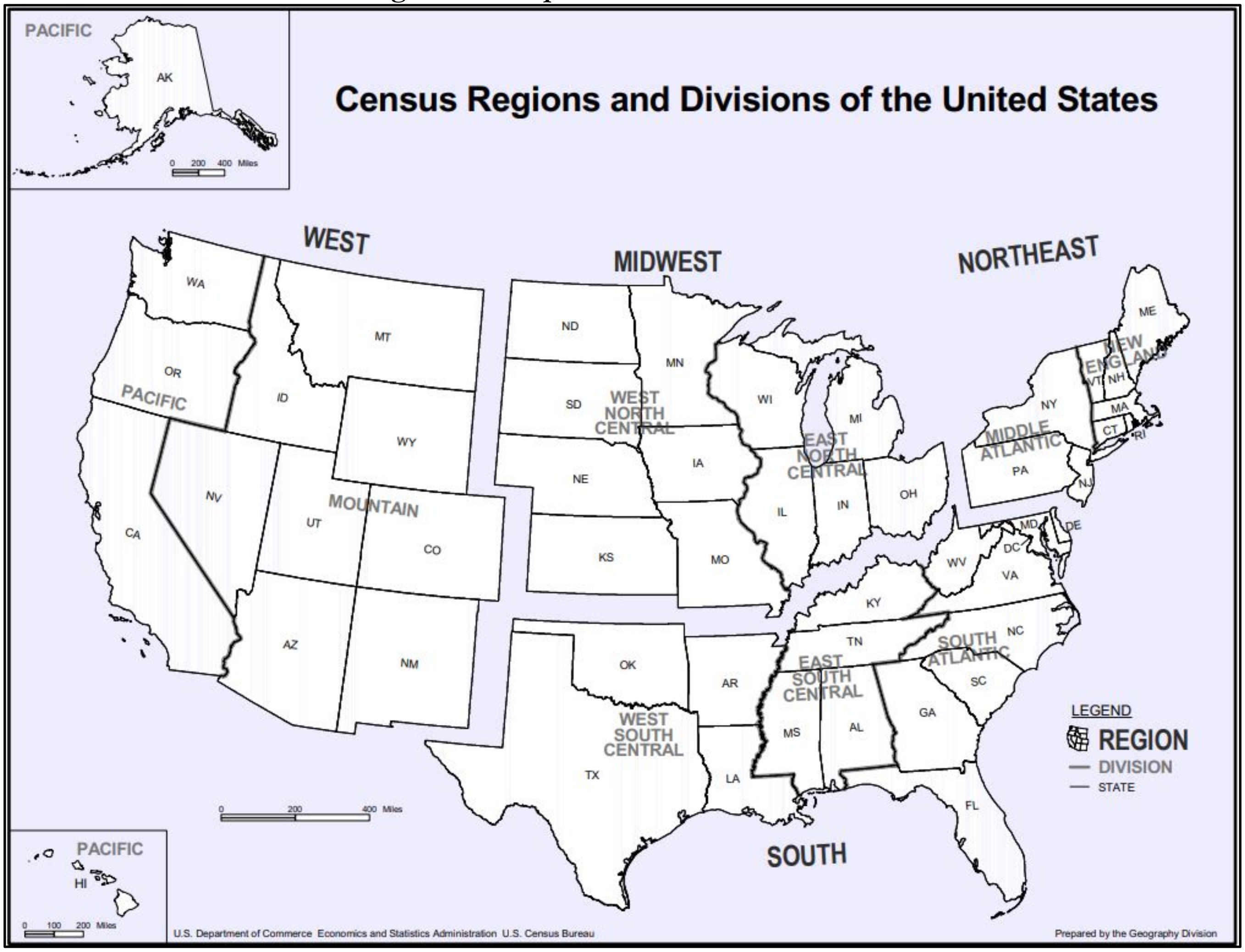
[2] *North American Reliability Corp.*, 163 FERC ¶ 61,094 (2018).

[3] *North American Reliability Corp.*, 167 FERC ¶ 61,095 (2019).

[4] Census Bureau, *Census Regions and Division of the United States*, https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf. *See* Appendix.

[5] Section 1252(e)(3) of the Energy Policy Act of 2005 requires the Commission to prepare and publish an annual report, *by appropriate region* … (emphasis added).

Figure 1-1: Map of U.S. Census Divisions



While utilities do not report a Census Division in Form EIA 861 data, utilities do report a state identifier and state-level information. Commission staff used the state identifier that utilities reported to EIA to present data by Census Division. A breakdown of the Census Divisions can be found in the Appendix to this report. To present accurate trends and to provide continuity, the analysis in this report presents findings by Census Division for the last two years that EIA Form 861 data are available (i.e., 2018 and 2019).

Highlights of the report include the following:

- From 2018 to 2019, the number of advanced meters[6] in operation in the United States increased by approximately 8 million to a total of 94.8 million, representing a 9% annual increase. According to

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[6] As defined by the EIA, advanced metering infrastructure (AMI) meters (also referred to throughout this report as "advanced meters") are "[m]eters that measure and record usage data[,] at a

EIA data, the 94.8 million advanced meters in operation represent 60.3% of the 157.2 million meters in the United States. While the advanced meter penetration rate varies by Census Division and customer class, the estimated advanced meter penetration rates nationwide for each of the residential, commercial, and industrial customer classes were greater than 50% in 2019.

- In 2019, utilities in the South Atlantic Census Division reported over 21 million advanced meters in operation, while utilities in the East North Central, Pacific, and West South Central Census Divisions each reported over 14 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 65%.

- State regulators across the country continue to support proposals to deploy advanced metering. States such as Connecticut and New Jersey are initiating proceedings and establishing frameworks for advanced metering proposals and proposal analysis. Increasingly, state regulators are proactively seeking different approaches to calculate the benefits and costs of advanced meter deployments beyond the traditional cost-benefit analysis prevalent for traditional utility investments.

- From 2019 to 2020, demand resource totals decreased in the wholesale markets by approximately 4% to a total of 30,787 MW. The aggregate decrease was concentrated in three regional transmission organization (RTO) and independent system operator (ISO) regions. Despite the nationwide decrease in demand resource totals from 2019 to 2020, wholesale demand resource potential to meet peak loads increased from 2019 to 2020 as a result of lower peak demand in 2020.

- From 2018 to 2019, customer enrollment in retail incentive-based demand response programs increased by 1.1 million, while customer enrollment in retail dynamic pricing programs increased by 1.7 million. These customer enrollment increases represent annual percentage increases of 12% and 19%, respectively.

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);

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

Other types of meters currently in use – such as standard electromechanical, standard solid state, and automated meter reading (AMR) meters, which collect data for billing purposes only and transmit this data one way – are not considered advanced meters for the purposes of this report. *See* EIA, Form EIA-861: Annual Electric Power Industry Report Instructions at 18, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

(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

Chapter 2 reports the penetration rate for advanced meters as well as state developments related to grid modernization and advanced metering. Table 2-1 shows that, according to EIA data, advanced meter deployments have increased in the United States by approximately 8 million meters for the third consecutive year, representing a 9% annual increase in the number of advanced meters from 2018 to 2019. Table 2-1 and Figure 2-1 show that, in 2019, there were approximately 94.8 million advanced meters installed and operational out of 157.2 million meters in the United States, representing an advanced meter penetration rate of 60.3%. In addition to the EIA data, the Edison Foundation's Institute for Electric Innovation reported a similar number and penetration rate for advanced meters in 2019, with a reported 99 million advanced meters in operation.

Table 2-1: Estimates of Advanced Meter Penetration Rates

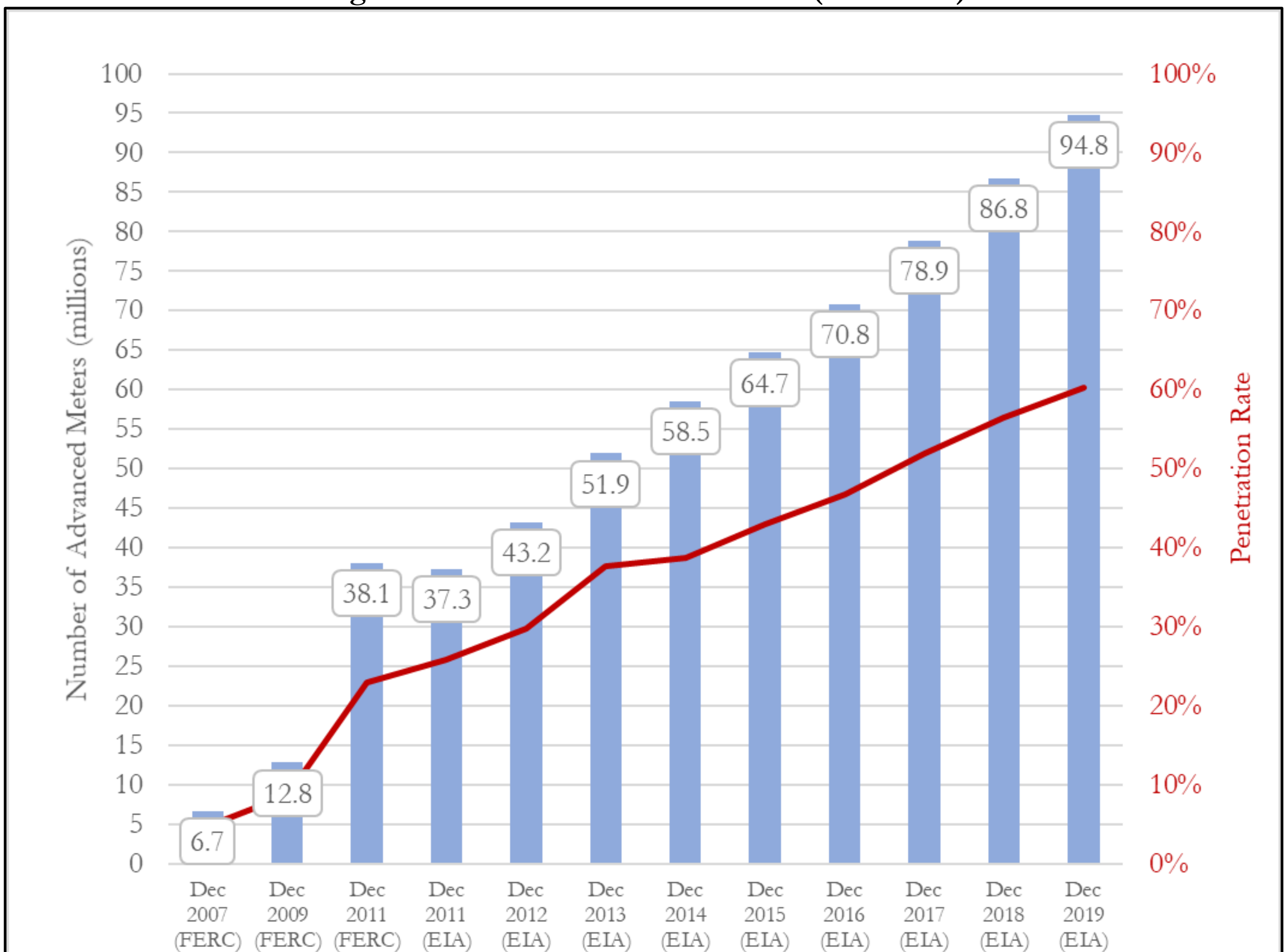
Data Source	Data as Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2008 FERC Survey[1]	Dec 2007 (FERC)	6.7	144.4	4.7%
2010 FERC Survey[2]	Dec 2009 (FERC)	12.8	147.8	8.7%
2012 FERC Survey[3]	Dec 2011 (FERC)	38.1	166.5	22.9%
2011 Form EIA-861[4]	Dec 2011 (EIA)	37.3	144.5	25.8%
Institute for Electric Efficiency[5]	May 2012 (IEE)	35.7	144.5	24.7%
2012 Form EIA-861[6]	Dec 2012 (EIA)	43.2	145.3	29.7%
Institute for Electric Innovation[7]	July 2013 (IEI)	45.8	145.3	31.5%
2013 Form EIA-861[8]	Dec 2013 (EIA)	51.9	138.1	37.6%
Institute for Electric Innovation[9]	July 2014 (IEI)	50.1	138.1	36.3%
2014 Form EIA-861[10]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[11]	Dec 2015 (EIA)	64.7	150.8	42.9%
Institute for Electric Innovation[12]	Dec 2015 (IEI)	65.6	150.8	43.5%
2016 Form EIA-861[13]	Dec 2016 (EIA)	70.8	151.3	46.8%
Institute for Electric Innovation[14]	Dec 2016 (IEI)	72.0	151.3	47.6%
2017 Form EIA-861[15]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[16]	Dec 2018 (EIA)	86.8	154.1	56.4%
Institute for Electric Innovation[17]	Dec 2018 (IEI)	88.0	154.1	57.1%
2019 Form EIA-861[18]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[19]	Dec 2019 (IEI)	99.0	157.2	63.0%

Sources: [1] FERC, *Assessment of Demand Response and Advanced Metering* (FERC DR AM Staff Report) (2008). [2] FERC DR AM Staff Report (2011). [3] FERC DR AM Staff Report (2012). [4] EIA-861 file_2_2011 and file_8_2011 (re-released May 20, 2014). The number of ultimate customers served by full-service and energy-only providers is used as a proxy for the total number of meters. [5] The Edison Foundation Institute for Electric Efficiency (IEE), *Utility-Scale Smart Meter Deployments, Plans & Proposals* (2012). [6] EIA-861 and EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (Oct. 29, 2013). [7] The Edison Foundation Institute for Electric Innovation (IEI), *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits* (2013). [8] EIA-861: Advanced_Meters_2013 data file (re-released Jun. 8, 2015). The number of total meters—including AMI, AMR, and standard electromechanical meters—was reported for the first time in 2013. Therefore, we no longer use the number of customers as a proxy. *See* source note 4 above and *Form EIA-861 Annual Electric Power Industry Report Instructions*, Schedule 6, Part D, http://www.eia.gov/survey/form/eia_861/proposed/2013/instructions.pdf. [9] IEI, *Utility-Scale Smart Meter Deployments: Building Block Of The Evolving Power Grid* (2014). [10] EIA-861: Advanced_Meters_2014 data file (re-released Jan. 13, 2016). [11] EIA-861: Advanced_Meters_2015 data file (re-released Nov. 1, 2016). [12] IEI, *Electric Company Smart Meter Deployments: Foundation for A Smart Grid* (2016). EIA-861: Advanced_Meters_2016 data file (re-released Nov. 6, 2017). [13] EIA-861: Advanced_Meters_2016 data file (re-released Nov. 6, 2017). [14] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2017). [15] EIA-861: Advanced_Meters_2017 data file (re-released Jan. 15, 2019). [16] EIA-861: Advanced_Meters_2018 data file (originally released October 2019, re-released Mar. 16, 2020). [17] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2019). The IEI report only lists the total number of advanced meters. [18] EIA-861: Advanced_Meters_2019 data file (released Oct. 6, 2020). [19] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2021).

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

Figure 2-1 below shows the growth of advanced meters from 2007 through 2019. Since 2007, the number of advanced meters in operation has increased by almost 90 million, from 6.7 million meters to more than 94.8 million meters in 2019. Advanced meters continue to be the most prevalent meter type in the United States and, in 2019, the penetration rate of advanced meters passed 60% for the first time. From 2018 to 2019, the number of advanced meters increased by approximately 8 million, or 9.2%, according to EIA data.

Figure 2-1: Advanced Meter Growth (2007–2019)



Note: years with more than one bar reflect data from multiple sources.

Table 2-2 below provides estimates of advanced meter penetration rates by Census Division and retail customer class. Data for 2019 show that aggregate totals of advanced meters reported by utilities in six of the nine Census Divisions represented advanced meter penetration rates above 50%, while aggregate totals reported by utilities in five Census Divisions represented advanced meter penetration rates equal to or greater than 65% of all meters. Utilities in the West South Central and Pacific Census Divisions reported the highest advanced meter penetration rates, with advanced meters accounting for approximately 74% of all meters. In contrast, the reported total number of advanced meters for utilities in the Middle Atlantic, New England, and West North Central Census Divisions represent penetration rates below 50% in 2019.

Table 2-2 also shows the advanced meter penetration rates for the residential, commercial, and industrial customer classes in 2019. For the second consecutive year, the overall advanced meter penetration rate for each of the residential, commercial, and industrial customer classes was greater than 50%. In 2019, the advanced meter penetration rate was highest in the residential and commercial customer classes at approximately 61% and 58%, respectively, followed closely by the industrial sector at 54%. Advanced meter penetration rates vary by region and customer class. In five Census Divisions, utilities reported the highest penetration of advanced meters in the residential customer class, while utilities in two Census Divisions reported a higher penetration rate of advanced meters in the industrial customer class. For the Mountain Census Division, both the residential and industrial classes had the same advanced meter penetration rate, at 51.5% of all meters in those classes. Overall advanced meter penetration rate for the commercial class was greater than that of the industrial customer class.

Table 2-2: Advanced Meter Penetration Rate by Customer Class and Census Division (2019)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	68.0%	64.5%	56.5%	67.6%
East South Central	68.8%	61.6%	51.7%	67.8%
Middle Atlantic	37.8%	34.5%	40.4%	37.4%
Mountain	51.5%	47.7%	51.5%	51.1%
New England	22.0%	24.6%	24.5%	22.3%
Pacific	74.0%	73.9%	64.0%	73.9%
South Atlantic	66.3%	62.5%	57.4%	65.8%
West North Central	43.5%	42.8%	58.6%	43.6%
West South Central	75.2%	71.1%	47.5%	74.4%
All Regions	**60.7%**	**57.8%**	**53.9%**	**60.3%**

Source: 2019 Form EIA-861 Advanced_Meters_2019 data file, 2019 Form EIA-861 Utility_Data_2019, 2018 Form EIA-861 Advanced_Meters_2018 data file, 2018 Form EIA-861 Utility_Data_2018.

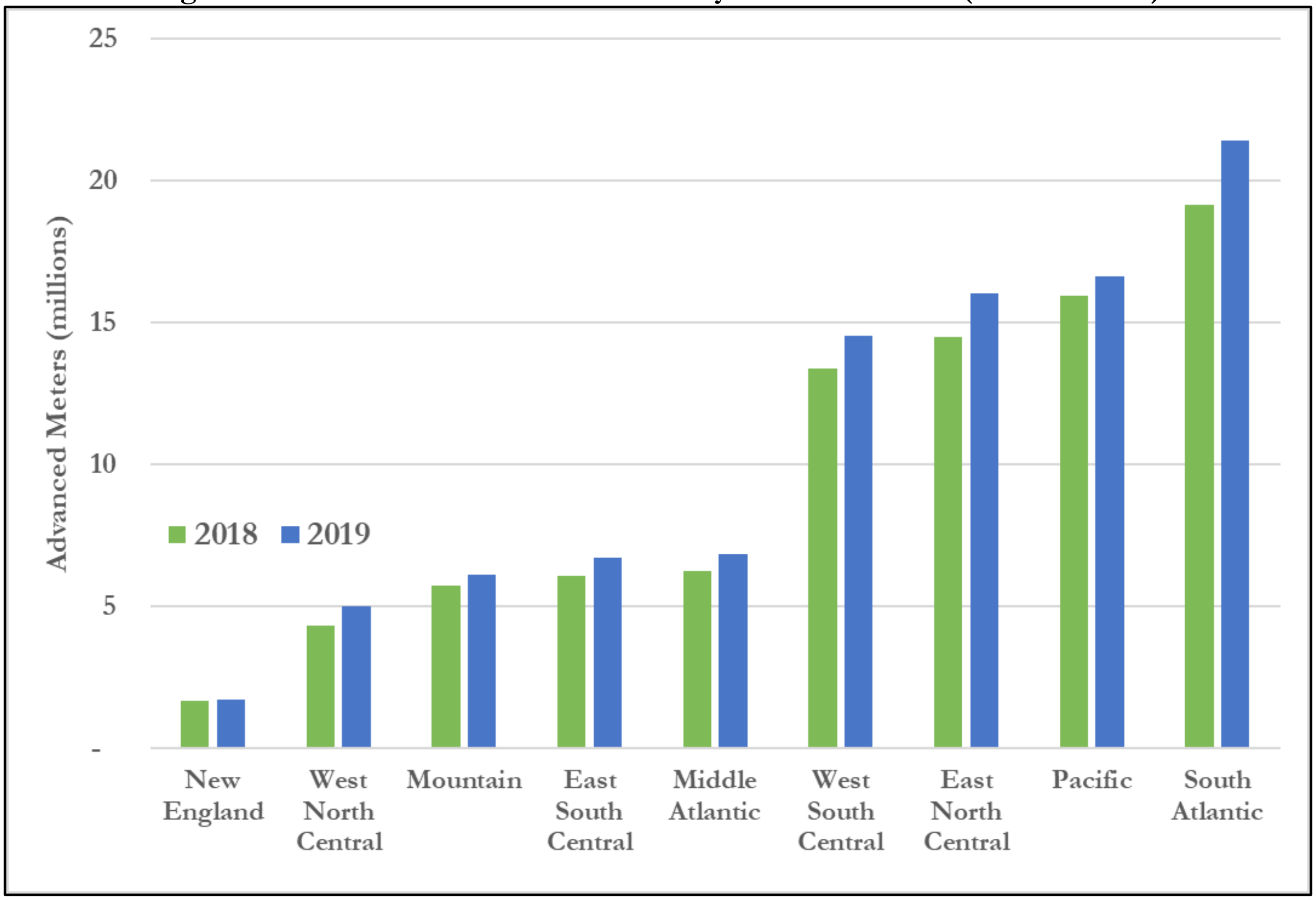
Note: The transportation sector data collected by EIA contain a relatively small number of meters and are not reported separately here. Although some utilities may operate in more than one state and Census Division, EIA data is broken down by utility at the state level. Commission staff has not independently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

Figure 2-2 displays the number of advanced meters by Census Division in 2018 and 2019. From 2018 to 2019, utilities in all nine Census Divisions reported aggregate increases in the number of advanced meters in operation. The largest percentage increases from 2018 to 2019 were reported by utilities in the West North Central, South Atlantic, and East North Central Census Divisions with reported increases of 16%, 12%, and 11%, respectively. In 2019, in the South Atlantic Census Division, 21 million advanced meters were reported by utilities, marking the first time utilities in a Census Division reported more than 20 million advanced meters in operation.

The West North Central Census Division had the largest percentage increase in advanced meters from 2018 to 2019 reported by utilities. Interstate Power and Light in Iowa reported 283,000 more advanced meters in 2019 compared with 2018, representing a 145% increase. Utilities in the South Atlantic Census Division reported approximately 2.3 million additional advanced meters in 2019 compared with 2018. The largest increases in the South Atlantic Census Division were from Duke Energy Florida with over 604,000 additional advanced meters, Tampa Electric Company with an additional 307,000 advanced meters, and Appalachian Power Company in Virginia with over 202,000 additional advanced meters. In the East North

Central Census Division, Ameren Illinois reported an increase of over 144,000 advanced meters, Southern Indiana Gas and Electric reported an additional 152,000 advanced meters, and the City of Lansing in Michigan reported 73,500 additional advanced meters. Finally, utilities in the West South Central, Pacific, East South Central, Middle Atlantic, Mountain, and New England Census Divisions reported aggregate increases of over 1.1 million, 686,000, 633,000, 589,000, 391,000, and 25,000 advanced meters, respectively.

Figure 2-2: Number of Advanced Meters by Census Division (2018 and 2019)



Developments and Issues in Advanced Metering

State Legislative and Regulatory Activities Related to Advanced Metering

As the penetration of advanced meters rises across the country, many state regulators are initiating proceedings in anticipation of additional advanced meter deployment proposals. For example, state regulators in Connecticut and New Jersey initiated proceedings that provide upfront clarity on how they expect utilities to unlock value from advanced meters and analyze the costs and benefits of advanced meter deployment. Additionally, New York regulators have provided direction on how to measure benefits of advanced meters beyond traditional cost-benefit analysis. As described in previous reports, some state regulators have characterized advanced meter deployment proposals as having incomplete or speculative benefit calculations and have required greater demonstration of costs and benefits in utility proposals. Changes and new proposals by utilities in some states may be in response to those concerns.

- **Connecticut**. On May 6, 2020, the Connecticut Public Utilities Regulatory Authority (Connecticut PURA) issued a final request for proposals for advanced meter business and implementation plans.[7] The request for proposals instructed utilities to present details on their advanced metering starting point, the business needs and value that full deployment of advanced meters will unlock, data and analytical tools to deliver operational efficiencies of advanced meters, and how advanced meters will enhance demand reduction strategies, among other state strategies.[8] The request for proposals also asked that utilities provide an analysis of costs and benefits, as well as a plan for deployment, metrics and evaluation, customer engagement, data privacy and security, and cost recovery.[9] In July 2020, United Illuminating and Eversource Energy both submitted proposals. United Illuminating proposed to deploy advanced meters across the remainder of its service territory, replacing 74,000 meters, by the end of 2024.[10] Eversource proposed to deploy advanced meters to its roughly 1.2 million residential and small commercial customers[11] and estimates that its AMI Plan will cost $612 million on a net present value basis.[12] After soliciting additional information and stakeholder input on the United Illuminating and Eversource submissions, the Connecticut PURA developed a draft proposal providing goals, expectations, and requirements for utilities to incorporate into their existing and future advanced meter deployment proposals.[13] Specifically, the proposal requires

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[7] *Notice of Release of Final Requests for Program Design and Proposals*, Docket No. 17-12-03RE02 (Connecticut PURA May 6, 2020) Attachment C, https://portal.ct.gov/-/media/PURA/electric/Notice-of-Release-of-Final-Requests-for-Program-Design-and-Proposals.pdf?la=en.

[8] *Id.* at 2.

[9] *Id.* at 2.

[10] *2020-2040 AMI Benefit Cost Analysis and Implementation Plan/Roadmap*, Docket 17-12-03RE02 (Connecticut PURA July 31, 2020) at 5, http://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/7a0bf0f5aaf643738525875200798f40/$FILE/2020-07-30%20UI%20AMI%20Benefit%20Cost%20Analysis%20and%20Implementation%20Plan%20&%20Roadmap%20%2317-12-03-RE02.docx.

[11] *PURA Investigation into Distribution System Planning of the Electric Distribution Companies - Advanced Metering Infrastructure, Proposal of Eversource Energy in Response to Request for Proposals for Advanced Metering Infrastructure Business and Implementation Plan,* Docket No. 17-12-03RE02, (July 30, 2021) at 2, http://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/5b7dc6ac9c2956968525875200798f57/$FILE/AMI%20Business%20and%20Implementation%20Plan%20ES%20200731%20FINAL.pdf.

[12] *Id.* at 6.

[13] *Attachment A – Straw Advanced Metering Infrastructure Program Design*, Docket 17-12-03RE02 (Connecticut PURA Aug. 17, 2021), http://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/00ed58d83bf06964852587520079953f/$FILE/17-12-03RE02%20AMI%20Straw%20Proposal%20Att%20A.pdf.

utilities to re-submit their advanced meter deployment proposals to include, among other things: a detailed timeline for advanced meter deployment; benefit calculations to be classified as "customer" or "operational" benefits; a plan to provide customers with information and online tools, such as real-time bill calculation; and separate rate design plans to explore the viability of an opt-in or opt-out provision for time-varying rates.[14] Utilities are required to submit their amended deployment plans by November 5, 2021.[15]

- **District of Columbia**. On March 25, 2021, the District of Columbia Public Service Commission (DC PSC) reconvened the Customer Impact Working Group to resolve issues raised in a Potomac Electric Power Company report on the feasibility of providing customers with access to energy usage data in a standardized, consumer-friendly format.[16] On September 9, 2021, the DC PSC directed the working group to prepare a report, within 90 days, including a timeline and cost estimate for implementing a "Connect My Data" platform.[17]

- **Minnesota.** In August 2018, the Minnesota Public Utilities Commission (Minnesota PUC) directed Xcel Energy's Northern States Power Company (Xcel Energy) to file annually an Integrated Distribution Plan.[18] In November 2019, Xcel Energy filed an Integrated Distribution Plan, which included a proposal to install 1.3 million advanced meters throughout its service territory.[19] On July

[14] *Id.* at 25.

[15] *Notice of Issuance of Straw Data Access and Privacy Program Design*, Docket 17-12-03RE02 (Connecticut PURA Aug. 17, 2021), http://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/00ed58d83bf06964852587520079953f/$FILE/17-12-03RE02%20Notice%20of%20Issuance%20of%20Straw%20Proposals.pdf.

[16] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Order No. 20717, Formal Case No. 1130 (DC PSC Mar. 25, 2021) at 13, https://edocket.dcpsc.org/apis/api/Filing/download?attachId=113804&guidFileName=d10a9844-aa11-4e02-850e-d1a348941f2f.pdf.

[17] *In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability*, Order No. 21013, Formal Case No. 1130 (DC PSC Sept. 9, 2021) at 10, https://edocket.dcpsc.org/apis/api/Filing/download?attachId=140983&guidFileName=e790ade0-1691-4b7c-b099-2ce3853158c8.pdf.

[18] *In the Matter of Distribution System Planning for Xcel Energy*, Docket No. E-002/CI-18-251 (Minnesota PUC Aug. 30, 2018) Attachment at 1, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF05A8C65-0000-CA19-880C-C130791904B2%7D&documentTitle=20188-146119-01.

[19] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666 (Minnesota PUC Nov. 1, 2019) Attachment M2 at 39, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E1276E-0000-CC54-B628-861D10E2F58D}&documentTitle=201911-157133-03.

23, 2020, the Minnesota PUC accepted Xcel Energy's Integrated Distribution Plan, including Xcel Energy's proposed deployment of advanced meters, subject to a future cost recovery proposal based upon Xcel Energy meeting performance metrics set by the Minnesota PUC.[20] On October 1, 2020, Xcel Energy submitted a compliance filing stating its expectation to install over 90% of the advanced meters proposed in its Integrated Distribution Plan by 2023. The compliance filing also noted that advanced meters are a key enabler for more complex rate structures, such as a three-period design in its time-of-use rate pilot, interactive demand response rate offerings, and critical peak pricing, among others.[21] Xcel Energy also stated that it will monitor energy usage levels and patterns to precisely calibrate rate design and rate components, while advanced meters will offer the opportunity to lower future systems costs by incenting changes in energy use as well as providing better data for future rate options.[22]

- **Montana.** On May 12, 2021, the Montana legislature passed a joint resolution requesting an interim study to examine future electric grid capacity requirements, grid technologies, and the roles of regulatory, private-sector, and state government entities in the future of the grid.[23] The resolution, noting the rapidly changing economic and technological environment of the electric industry in the state, directed a study on the contributions of non-generation technologies, including advanced meters and demand-side management, to achieve a more efficient grid.[24] The legislature directed that the study be completed by September 15, 2022.[25]

- **New Jersey.** In February 2020, the New Jersey Board of Public Utilities (New Jersey BPU) lifted its moratorium on the pre-approval of advanced metering and ordered Atlantic City Electric, Jersey

[20] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E-002/M-19-666 (Minnesota PUC July 23, 2020) at 12, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F00E7D73-0000-CD15-B6E0-EA73F0AC037E}&documentTitle=20207-165209-01.

[21] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666 (Minnesota PUC Oct. 1, 2020) at 11-12, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={70E3E574-0000-CF14-ADDE-8996903AF146}&documentTitle=202010-167007-0.

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

[23] Joint Resolution, SJ 33, 67th Minnesota Legislature (2021) at 1, https://leg.mt.gov/bills/2021/billpdf/SJ0033.pdf.

[24] *Id.* at 2.

[25] *Id.* at 2.

Central Power and Light, and Public Service Electric and Gas to file petitions to implement advanced meters or update previously filed advanced meter implementation petitions.[26]

In response to the February 2020 order, Public Service Electric and Gas updated a previously-filed advanced meter deployment plan on April 1, 2020.[27] The updated proposal entailed a $714 million capital investment over five years along with an additional $71 million for operations and maintenance.[28] On December 24, 2020, Public Service Electric and Gas filed a fully executed Stipulation, which included a plan to install approximately 2.2 million advanced meters through 2024 at a total expenditure of $778 million.[29] On January 7, 2021, the New Jersey BPU adopted the Stipulation, with cost recovery to be reviewed in a subsequent rate case.[30]

In August 2020, Jersey Central Power & Light filed for approval of an advanced meter program to install 1.15 million advanced meters over the three-year period ending in December 2025 at an estimated total cost of $732 million.[31] On January 13, 2021, the New Jersey BPU issued a prehearing order and set a procedural schedule to review the cost effectiveness of the proposal and the reasonableness of the cost recovery mechanism.[32] On March 10, 2021, the New Jersey BPU

[26] *In the Matter of the Petition of Rockland Electric Company for Approval of an Advanced Metering Program; and for Other Relief*, Docket No. ER16060524 (New Jersey BPU Feb. 24, 2020) at 3, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1218779.

[27] *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Cloud Program on a Regulated Basis*, Docket No. EO18101115 (New Jersey BPU Jan. 7, 2021) at 2, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1231760.

[28] *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Cloud Program on a Regulated Basis*, Docket No. EO18101115 (New Jersey BPU Dec. 24, 2020) at 3-4, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1231434.

[29] *Id.*

[30] *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Cloud Program on a Regulated Basis*, Docket No. EO18101115 (New Jersey BPU Jan. 7, 2021) at 13, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1231760.

[31] *In the Matter of the Petition of Jersey Central Power & Light Company for Approval of an Advanced Metering Infrastructure Program*, Docket No. EO20080545 (New Jersey BPU Aug. 27, 2020) at 3-4, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1224763.

[32] *In the Matter of the Petition of Jersey Central Power & Light Company for Approval of an Advanced Metering Infrastructure Program*, Docket No. EO20080545 (New Jersey BPU Jan. 13, 2021) at 12, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1231995.

suspended the procedural schedule set forth in the January 2021 Order so that the parties could continue to work toward a possible settlement.[33]

On August 26, 2020, Atlantic City Electric filed an advanced meter proposal to replace all meters in its service territory at a cost of $220 million.[34] On March 18, 2021, the New Jersey BPU suspended the procedural schedule to allow parties to negotiate a possible settlement.[35] In July 2021, the New Jersey BPU adopted a stipulation of settlement that included replacement of roughly 568,000 meters by the middle of 2024 at a cost of $177 million.[36] As part of the stipulation, the New Jersey BPU will review the advanced meter cost recovery in Atlantic City Electric's next rate case to be filed no later than January 2023.[37]

- **New Mexico.** On April 7, 2021, the governor of New Mexico signed legislation providing several clarifications for public utilities seeking state approval for grid modernization projects.[38] The legislation defined grid modernization as investments in assets, technologies, or services that are designed to modernize electrical infrastructure "by enhancing electric distribution or transmission grid reliability, resilience, interconnection of distributed energy resources, distribution system efficiency. . . customer service or energy efficiency and conservation."[39] Within this definition, the legislation explicitly included advanced meters and associated communications networks.[40]

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[33] *In the Matter of the Petition of Jersey Central Power & Light Company for Approval of an Advanced Metering Infrastructure Program*, Docket EO20080545 (New Jersey BPU Mar. 3, 2021) at 2, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1237307.

[34] *In the Matter of the Petition of Atlantic City Electric Company for Approval of a Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief*, Docket No. EO20080541 (New Jersey BPU Aug. 26, 2020) at 1, 4, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1224713.

[35] *In the Matter of the Petition of Atlantic City Electric Company for Approval of a Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief*, Docket EO20080541 (New Jersey BPU Mar. 18, 2021) at 2, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1237913.

[36] *In the Matter of the Petition of Atlantic City Electric Company for Approval of a Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief*, Docket EO20080541 (New Jersey BPU July 14, 2021) at 4, https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1244177.

[37] *Id.* at 14.

[38] Utility Distribution System Hardening, New Mexico Laws 2020 Ch. 15 § 3, N.M. Stat. Ann. § 62-8-13 (2021), https://www.nmlegis.gov/Sessions/21%20Regular/final/HB0245.pdf.

[39] *Id.* at 4.

[40] *Id.*

- **New York.** On November 20, 2020, the New York Public Service Commission (New York PSC) approved National Grid's plan in its Niagara Mohawk service territory to deploy 1.7 million advanced meters across its service territory by March 2027 at a cost of approximately $474 million.[41] Along with the deployment of advanced meters, the order also required that National Grid provide data to mass market customers in 15-minute intervals.[42] As directed in the November 2020 order, National Grid filed a "Benefit Implementation Plan" on January 20, 2021, which included an analysis of the quantifiable and unquantifiable benefits that advanced meters can provide, together with specific implementation steps and interim milestones to achieve those benefits.[43]

Collaborative Industry-Government Efforts

The OpenADR Alliance was formed in 2010 to enable stakeholders to participate in automated demand response, distributed energy resource (DER) management, and dynamic pricing using the OpenADR standard. OpenADR is a two-way information exchange model and Smart Grid standard that standardizes the message format used for automated demand response and DER management between utilities, RTOs/ISOs, and energy management and control systems. In October 2020, OpenLEADR was deployed as an open source, standardized code implementation of the OpenADR standard.[44] The OpenLEADR code was originally developed for electric vehicle charging infrastructure, and The OpenADR Alliance expects that availability and use of OpenADR will increase by using OpenLEADR as an open source platform for OpenADR.

The North American Energy Standards Board is an industry forum to develop standards for wholesale electric and natural gas markets. In February 2021, the North American Energy Standards Board announced the initiation of a standards development process to support integration of battery storage and

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[41] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Case No. 17-E-0238 (New York PSC Nov. 20, 2020) at 5-6, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={7F47DEF5-3F7F-4191-9A2A-FE0803682FDD}.

[42] *Id.* at 52.

[43] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Case No. 17-E-0238 (New York PSC Jan. 20, 2021), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={923313F3-41F2-47D4-A199-CA11C1FB5D97}.

[44] OpenADR Alliance, *LF Energy Launches openLEADR to Streamline Integration of Green Energy for Demand Side Management* (Oct. 2020), https://www.openadr.org/index.php?option=com_content&view=article&id=192:lfenergy-creates-open-source-project&catid=21:press-releases&Itemid=121.

DERs in wholesale markets in response to Commission Order Nos. 841 and 2222.[45] In a June 2021 informational filing to the Commission, the North American Energy Standards Board stated that efforts included exploration of information and reporting requirements as well as information exchange, such as data communicated between energy storage asset owners or DER aggregators and RTOs/ISOs.[46]

[45] North American Energy Standards Board, *NAESB to Address Battery Storage/Distributed Energy Resources and Renewable Natural as in 2021* (Feb. 17, 2021), https://www.naesb.org/pdf4/021721press_release.pdf.

[46] North American Energy Standards Board, Informational Filing, Docket No. RM05-5-000, at 2 (filed June 21, 2021).

3. Annual Resource Contribution of Demand Resources

Chapter 3 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 RTOs/ISOs.

Retail Demand Response Programs

Table 3-1 presents data on potential peak demand savings from retail demand response programs by Census Division. 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."[47] From 2018 to 2019, potential peak demand savings in the United States increased by approximately 125 MW, or 0.4%, from 30,895 MW to approximately 31,020 MW. In 2018 and 2019, utilities in the South Atlantic, West North Central, and East North Central Census Divisions reported the greatest potential peak demand savings.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2018 and 2019)

Census Division	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2018	2019	MW	%
East North Central	4,708.0	5,362.8	654.8	13.9%
East South Central	4,600.2	4,343.1	-257.1	-5.6%
Middle Atlantic	1,632.9	1,463.6	-169.3	-10.4%
Mountain	2,128.2	1,968.0	-160.2	-7.5%
New England	245.2	179.3	-65.9	-26.9%
Pacific	2,213.0	1,803.2	-409.8	-18.5%
South Atlantic	7,939.8	8,106.8	167.0	2.1%
West North Central	5,045.1	5,554.1	509.0	10.1%
West South Central	2,382.6	2,238.7	-143.9	-6.0%
Total	**30,895.0**	**31,019.5**	**124.5**	**0.4%**

Source: EIA, EIA-861 Demand_Response_2018, Demand_Response_2019, Utility_Data_2018, and Utility_Data_2019 data files.

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

[47] *See* 2019 Form EIA 861 Schedule 6, Part B: Demand Response Programs.

Figure 3-1 below shows retail potential peak demand savings by Census Division in 2018 and 2019. Despite the overall increase in retail potential peak demand savings, utilities in only three of the nine Census Divisions reported aggregate annual increases. Utilities in the East North Central Division reported the largest annual increase in retail potential peak demand savings, with an increase of 655 MW, or 13.9%, from 2018 to 2019. Commonwealth Edison in Illinois, Indiana Michigan Power Company in Indiana, and Consumers Energy Company in Michigan, which are located in the East North Central Census Division, each reported large annual increases in potential peak demand savings. Duke Energy Carolinas in North and South Carolina and Baltimore Gas and Electric in Maryland, both located in the South Atlantic Census Division, also reported large annual increases in potential peak demand savings. Northern States Power Company in Minnesota reported an increase in potential peak demand savings in the West North Central Census Division. Despite reported overall decreases in six of the Census Divisions, some utilities in those Census Divisions reported increases in potential peak demand savings. For example, Consolidated Edison Company in New York in the Middle Atlantic Census Division and Portland General Electric in the Pacific Census Division reported increases in potential peak demand savings despite the aggregate decreases reported by utilities in these Census Divisions.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2018 and 2019)

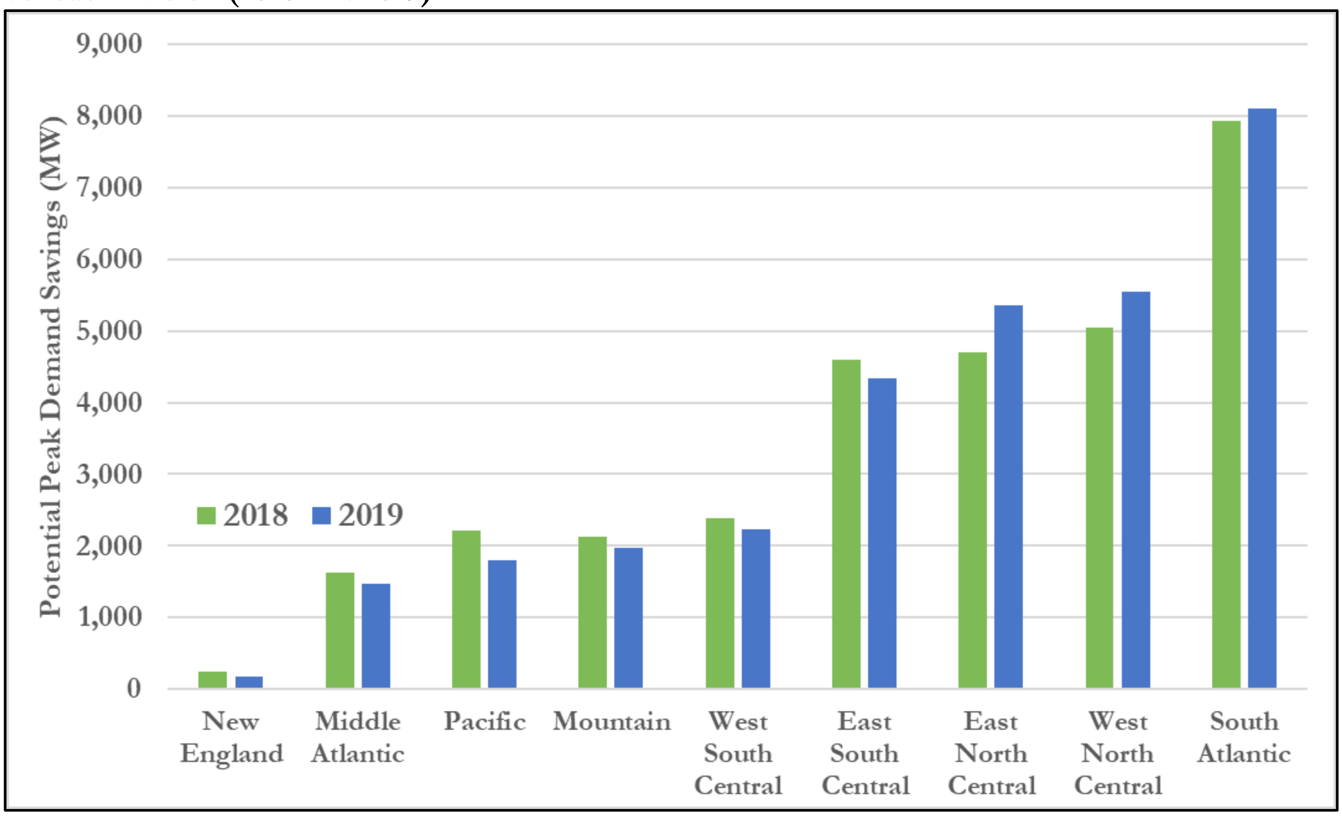

Table 3-2 below shows the relative contribution of retail potential peak demand savings in 2019 from the residential, commercial, and industrial customer classes. In 2019, utilities reported over 15,000 MW of potential peak demand savings from the industrial customer class, roughly half of the reported total. In six of the nine Census Divisions, reported potential peak demand savings were greatest in the industrial customer class. The relative contribution of potential peak demand savings from the residential and commercial sectors was similar to their contribution in 2018, at 29% and 22%, respectively. With a total of nine states, the South Atlantic Census Division is the largest by number of states and accounted for roughly one quarter of all reported potential peak demand savings in 2019.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division and Customer Class (2019)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	795.4	1,229.4	3,338.0	5,362.8
East South Central	353.2	182.4	3,807.5	4,343.1
Middle Atlantic	225.6	443.5	794.5	1,463.6
Mountain	857.8	442.1	668.1	1,968.0
New England	78.0	83.1	18.2	179.3
Pacific	453.3	306.8	1,043.1	1,803.2
South Atlantic	3,475.0	2,504.0	2,127.9	8,106.8
West North Central	2,183.4	1,053.9	2,316.7	5,554.1
West South Central	445.3	661.7	1,131.7	2,238.7
Total	**8,866.9**	**6,906.9**	**15,245.7**	**31,019.5**

Source: EIA, EIA-861 Demand_Response_2019, and Utility_Data_2019 data files.

Note: Although some utilities may operate in more than one state and Census Division, EIA data is broken down 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 presents demand response resource participation in RTO/ISO[48] wholesale demand response programs in 2019 and 2020. Demand resource participation in the wholesale markets decreased by approximately 1,383 MW, or 4%, from 2019 to 2020. However, on a regional basis, demand response resource totals increased in four of the seven wholesale markets. The largest annual difference occurred in PJM, where there was a reported decrease of 1,270 MW in demand response resources from 2019 to 2020. Despite the year-on-year decrease, the percent of peak demand that could be met by demand response resources increased from 6% in 2019 to 6.6.% in 2020 because of lower peak loads.

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

Table 3-3: Demand Response Resource Participation in RTOs/ISOs (2019 & 2020)

RTO/ISO	2019		2020		Year-on-Year Change	
	Demand Resources (MW)	Percent of Peak Demand [8]	Demand Resources (MW)	Percent of Peak Demand [8]	MW	Percent
CAISO [1]	3,200.0	7.2%	3,290	7.0%	90.0	2.8%
ERCOT [2]	3,551.8	4.8%	3,939.0	5.1%	387.2	6.3%
ISO-NE [3]	454.8	1.9%	476.2	1.9%	21.4	4.7%
MISO [4]	13,375.0	11.1%	13,024.0	11.1%	-351.0	-2.6%
NYISO [5]	1,404.0	4.6%	1,274.1	4.2%	-129.9	-9.3%
PJM [6]	10,185.0	6.9%	8,915.0	6.0%	-1,270.0	-12.5%
SPP [7]	0.3	0.0%	34.2	0.1%	33.9	11,300.0%
Total	**32,170.9**	**6.0%**	**30,787.5**	**6.6%**	**-1,383.3**	**-4.3%**

Sources: [1] CAISO, 2019 and 2020 Annual Reports on Market Issues and Performance. Totals for 2020 were confirmed in Commission staff discussions with CAISO Department of Market Monitoring staff; [2] Estimated based on ERCOT, 2019 and 2020 Annual Reports of Demand Response in the ERCOT Region; [3] ISO-NE, Monthly Statistics Report, presented at December 2019 and July 2020 Demand Resources Working Group Meetings; [4] Potomac Economics, 2019 and 2020 State of the Market Reports for the MISO Electricity Markets. Values for demand response in the 2019 State of the Market Report for MISO were reported differently in the 2020 State of the Market Report. The 2021 Assessment of Demand Response and Advanced Metering has updated the 2019 values using totals from the 2020 State of the Market report for comparison to values for 2020 from the 2020 State of the Market Report for MISO. [5] NYISO, 2019 and 2020 Annual Reports on Demand Side Management Programs of the New York Independent System Operator, Inc.; [6] PJM, 2019 and 2020 Demand Response Operations Markets Activity Reports. Totals represent "unique MW"; [7] SPP, 2019 and 2020 State of the Market Reports; [8] Sources for peak demand data include: CAISO 2019 and 2020 Annual Reports on Market Issues and Performance; ERCOT 2018 & 2019 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report (July 2020 and July 2021); 2019 and 2020 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2018 and 2019; 2019 and 2020 PJM State of the Markets Reports, Vol. 2; SPP 2019 and 2020 State of the Market Reports.

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

CAISO reported similar totals in demand response capability in 2020 compared to 2019. Proxy Demand Resource (PDR) capacity in CAISO increased by 60 MW, from 1,700 MW in 2019 to 1,760 MW in 2020. Similarly, Reliability Demand Response Resource (RDRR) capacity increased from 1,500 MW in 2019 to 1,530 MW in 2020.

Demand response resource participation totals in ERCOT increased by 222 MW, or 6.3%, from 2019 to 2020 to 3,774 MW. ERCOT reported an increase of 194 MW in demand response resources providing frequency response through the Responsive Reserve Service program. ERCOT also reported an increase of 28 MW, or 3.8%, in resources providing Emergency Response Service.

ISO-NE's price responsive demand program, which dispatches demand response resources based on energy market offers, marked its third year of operation in 2020. Participation in the program decreased by 21 MW from 2019 to 2020, to a total of 423 MW of Active Demand Capacity Resources enrolled in July 2020, the month of the highest peak demand in ISO-NE.

Demand response resource capability in MISO decreased by 351 MW, or 2.6%, to a total of 13,024 MW from 2019 to 2020. In 2020, the market monitor for MISO reported totals for demand response and energy efficiency separately, which contributed to the year-on-year decrease in demand response capability. However, from 2019 to 2020, Load Modifying Resource (LMR) capability in MISO increased by 39 MW. LMRs can be used to meet MISO's planning reserve requirements and must curtail load during emergency conditions. Demand Response Resource Type I and II resources are demand response resources that economically respond to prices in the energy and ancillary services markets. From 2019 to 2020, combined registration totals of Demand Response Resource Type I and II in MISO decreased by 5 MW, from 899 MW to 894 MW.

In NYISO, demand response resource registration decreased by 130 MW, or approximately 9%, from 2019 to 2020. The annual decrease is attributable to a decline in registration in two programs: Special Case Resources, which are demand-side resources that offer unforced capacity into NYISO's Installed Capacity Market, and demand resources providing operating reserves in NYISO's economic Demand-Side Ancillary Services Program. In 2020, demand resource registration in NYISO's Special Case Resource program totaled 1,195 MW, a decrease of approximately 87 MW, or roughly 7%, from 2019. Participation in NYISO's Demand-Side Ancillary Services Program decreased by 41.5 MW, or 35%, from 2019 to 2020. Despite the decrease in the number of MW participating, NYISO noted that these demand response resources had an average performance of 100.8% between May 2020 and October 2020, indicating that the resources reduced demand by more than NYISO requested.[49]

The largest annual decrease in demand response resource capability reported by an RTO/ISO occurred in PJM. The 2020/2021 Delivery Year was the first year that all resources procured in the PJM capacity market were obligated to meet the annual Capacity Performance requirements. The total capacity procured by the capacity market decreased, as did the amount of demand response that cleared.[50] From 2019 to 2020, total demand response resource capability in PJM decreased by 1,270 MW, or 12%, from 10,185 MW to 8,915 MW. In 2020, PJM's new Price Responsive Demand program went into operation in PJM's energy markets, with 612 MW of price responsive demand capability registered in the program.

In 2020, SPP reported a total of 34.2 MW of demand response capability from 34 demand response resources. This represents an increase of approximately 33 MW from 2019, when SPP reported a total of 0.3 MW of demand response resources.

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[49] NYISO, *NYISO 2020 Annual Report on Demand Response Programs*, (Jan. 2020) at 5, https://www.nyiso.com/documents/20142/18508130/NYISO-2020-Annual-Report-on-Demand-Response-Programs-FINAL.pdf/820330e8-d51f-9315-fa01-c6590a62013a.

[50] PJM, *2020/2021 RPM Base Residual Auction Results*, (May 2017) at 1-2, https://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.

Demand Response Deployments

RTOs/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 from notable demand response events.

In February 2021, due to severe weather and significant generation outages, ERCOT instituted voluntary and involuntary load reductions to prevent an interconnection-wide blackout. The University of Texas at Austin Energy Institute, using data from ERCOT and through an agreement with the Public Utility Commission of Texas, issued a report detailing the events and causes of the blackouts, as well as other findings. The report noted that the average amount of Responsive Reserve Service provided by loads in February 2021 was 1,259 MW, which is 289 MW lower than the average of 1,548 MW provided by load resources in January 2021.[51] However, the report found that maximum load reductions from resources providing Responsive Reserve Service were over 1,400 MW on February 15, 16, and 17.[52] During the severe weather, ERCOT also reduced demand by deploying resources in the Emergency Response Service (ERS) program.[53] The ERS program achieved its targeted level of demand reduction of 1,100 MW on the morning of February 15, 2021.[54] Further, an ERCOT assessment of demand-side resources found that ERS Loads met and exceeded their obligations on February 14 and 15. ERCOT noted that the aggregate ERS Load fleet contributed 30% to 35% more than its combined obligations while the ERS Generator fleet only provided approximately 70% to 75% of its combined obligation.[55] In addition to actions directed by

[51] The University of Texas at Austin Energy Institute, *The Timeline of Events of the February 2021 Texas Electric Grid Blackout*, (July 2021) at 38, https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout%2020210714.pdf.

[52] *Id.* at 38.

[53] The Emergency Response Service allows ERCOT to select "qualified loads and generators (including aggregations of loads and generators) to make themselves available for deployment in an electric grid emergency". *See* ERCOT, *Emergency Response Service*, http://www.ercot.com/services/programs/load/eils.

[54] *Id.* at 38, 39.

[55] ERCOT, *ERCOT Winter Storm Review of Demand-Side Resources and Other Related Topics* (Apr. 2021) at slides 6, 8, http://www.ercot.com/content/wcm/key_documents_lists/226624/April_2021_DSWG_Meeting_ERCOT_FINAL.PPTX.

ERCOT, utilities, most notably CPS Energy[56] in San Antonio and Austin Energy,[57] called on customers to reduce electric and natural gas consumption.

On November 16, 2021, staff from the Commission, NERC, and the NERC Regional Entities issued a report on the winter cold weather outages in Texas and the South Central United States. The report recommended revising Reliability Standards to prohibit the use of critical natural gas infrastructure loads for demand response by Winter 2023-2024.[58] In addition, the report recommends that RTOs/ISOs and/or state public utility commissions pursue additional voluntary demand response programs and resources to allow grid system operators to quickly respond to grid emergencies.[59]

During the week of February 15, 2021, the MISO region experienced unusually cold weather that increased demand and reduced supply due to weather-related generation performance issues and fuel availability.[60] During the evening peak on February 16, 2021, MISO declared a Maximum Generation Event and committed Emergency Demand Response and coordinated with members to issue public appeals for energy conservation.[61] On June 10, 2021, MISO declared a Maximum Generation Warning for its North and Central Regions. A Maximum Generation Warning requires that market participants and local balancing authorities update LMR availability and ensure preparedness for Load Management Measures.[62] MISO later issued a Maximum Generation Event Step 2 in the North and Central Regions on June 10, 2021.[63] During a Maximum Generation Emergency Event Step 2a, local balancing authorities in MISO are required to reduce load and, as directed by MISO, make use of LMRs and other load management practices. DER aggregators

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[56] CPS Energy, *Weather and Safety Update* (Feb. 14, 2021), https://newsroom.cpsenergy.com/update-as-of-sunday-february-14-2021-400-pm-winter-weather-and-extreme-cold-puts-community-at-risk-state-grid-operator-and-cps-energy-call-for-customers-to-reduce-electric-and-natural-gas-use/.

[57] Austin Energy, *EEA1: Electric Grid Operator Requests Conservation* (Feb. 15, 2021), https://austinenergy.com/ae/about/news/news-releases/2021/ee1-electric-grid-operator-requests-conservation.

[58] FERC-NERC-Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States*, (Nov. 16, 2021) at 19, 207, https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[59] *Id.* at 226-227.

[60] MISO, *The February Arctic Event: Event Details, Lessons Learned, and Implications for MISO's Reliability Imperative*, (Sep. 2021) at 4, https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf.

[61] *Id.* at 6, 7.

[62] MISO, *Max Gen Warning North and Central Regions effective 06/10/2021*, https://www.misoenergy.org/mcsnotification/?id=1176.

[63] MISO, *Max Gen Event North and Central Regions - EEA 2 effective 06/10/2021*, https://www.misoenergy.org/mcsnotification/?id=1177.

provided over 400 MW during the three-hour LMR dispatch and reported delivering more than their commitment during the event called by MISO.[64]

In 2021, CAISO issued Statewide Flex Alerts, encouraging consumers to conserve electricity during peak hours and times of system stress, for June 17 and 18, July 9, 10, 12, and 28, and September 8 and 9.[65] On July 9, 2021 CAISO issued a Grid Stage 2 System Emergency Notice.[66] During a Grid Stage 2 System Emergency, CAISO directs utilities to call on participating customers to reduce load under emergency demand response programs.[67] CAISO also issued a Grid Warning for July 29, 2021 after forecasting a resource deficiency. Declaration of a Grid Warning allows CAISO to activate RDRR programs from large users to reduce electric demand.[68] Additionally, Stem, which is a market participant that provides energy storage services, dispatched available capacity from its resources enrolled in demand response programs in response to Flex Alerts during the week of June 14, 2021 in California.[69]

On June 30, 2021, Con Edison in New York asked 3.5 million of its customers in and around New York City to limit energy use during high temperatures when it projected a peak demand of 12,300 MW, 560 MW higher than the peak demand of 11,740 MW in 2020.[70] In the notice, Con Edison urged customers not to use energy-intensive appliances and limit use of other necessary appliances, such as air conditioning. Within 30 minutes of the announcement urging energy conservation, demand fell by 263 MW.[71]

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[64] SmartGrid Today, *Voltus DER-Based DR Beats Commitment to MISO Event* (July 20, 2021), https://www.smartgridtoday.com/members/Voltus-DERbased-DR-beats-commitment-to-MISO-event.cfm.

[65] CAISO, *FlexAlert*, http://www.flexalert.org/news.

[66] RTO Insider, *CAISO Declares Emergency as Fire Derates Major Tx Lines*, (July 9, 2021), https://www.rtoinsider.com/articles/28185-caiso-issues-warning-as-fire-derates-major-tx-line.

[67] CAISO, *Operating Procedure No. 4420C, System Emergency Notice Templates*, (August 20, 2021) http://www.caiso.com/Documents/4420C.pdf.

[68] CAISO, *System Conditions Bulletin* (July 29, 2021), https://www.caiso.com/Documents/SystemConditionsBulletin.pdf.

[69] SmartGrid Today, *Stem Shares Details About Helping in June Heatwave* (July 2, 2021), https://www.smartgridtoday.com/members/login.cfm?hpage=Stem-shares-details-about-helping-in-June-heatwave.cfm.

[70] Con Edison, *Con Edison Asking Customers to Conserve on Day Four of Intense Heat Wave* (June 30, 2021), https://www.coned.com/en/about-us/media-center/news/20210630/con-edison-asking-customers-to-conserve-on-day-four-of-intense-heat-wave.

[71] S&P Global Platts, *New York City Calls on Households, Businesses to Cut Power Use Amid Heat Wave* (July 1, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/070121-new-york-city-calls-on-households-businesses-to-cut-power-use-amid-heat-wave.

Utilities in the Pacific Northwest also urged reductions in customer demand during record-breaking heat in June 2021. On June 24, 2021 Idaho Power, [72] Portland General Electric, [73] and Puget Sound Energy[74] issued public notices in preparation for extreme heat and high demand, encouraging customers to reduce electricity consumption and shift demand to off-peak hours.

Update on California Summer 2020 Events

In summer 2020, California and other parts of the western United States experienced extreme heat, forcing CAISO to call on demand response resources and institute rotating outages. In January 2021, CAISO, the California Public Utilities Commission (California PUC), and the California Energy Commission (CEC) released a Final Root Cause Analysis on the summer 2020 events that found extreme weather, resource adequacy and planning processes, and market practices as the three primary factors that contributed to the outages.[75] In the report, CAISO measured August 2020 demand response performance as the metered load drop relative to the amount of demand response that was dispatched or that received awards in real time. According to CAISO, during Stage 3 Emergency[76] hours on August 14, RDRR from Investor Owned Utility (IOU) programs provided 81% of the metered load drop they were dispatched to provide, IOU operated PDR provided 68% of the metered load drop they were dispatched to provide, and non-IOU operated PDR provided 41% of the metered load drop they were dispatched to provide.[77] During Stage 3 Emergency hours on August 15, RDRR performance increased to 85%, while IOU operated PDR and non-IOU operated PDR performance decreased to 30% and 25%, respectively, of the metered load drop they were dispatched to provide.[78]

In their recommendations in the Final Root Cause Analysis, CAISO, California PUC, and CEC noted that further study on reducing the gap between dispatch levels and actual metered load drop is needed, especially

[72] Idaho Power, *Idaho Power Asks Customers to Conserve Energy During Evening Hours* (June 24, 2021), https://www.idahopower.com/news/idaho-power-asks-customers-to-conserve-energy-during-evening-hours/.

[73] Portland General Electric, *PGE Prepares for Extreme Heat and High Electric Use – Encourages Customers to be Prepared, Too* (June 24, 2021), https://portlandgeneral.com/news/2021-06-24-pge-prepares-for-extreme-heat-and-high-electric-use.

[74] Puget Sound Energy, *PSE Offers Hot Weather Tips as Temperatures Heat Up* (June 24, 2021), https://www.pse.com/press-release/details/PSE-offers-hot-weather-tips-as-temperatures-heat-up

[75] CAISO, *Final Root Cause Analysis* (Jan. 2021) at 3-5, http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (Final Root Cause Analysis).

[76] *Id.* at 24. A Stage 3 Emergency is declared by CAISO when it is unable to meet minimum contingency reserve requirements, and load interruption is imminent or in progress. CAISO also issues a notice to utilities of potential electricity interruptions through firm load shedding.

[77] *Id.* at 56.

[78] *Id.*

with non-IOU demand response resources.[79] The baseline methodology used to measure a demand response resource's expected load absent its demand reduction may have also contributed to the difference between dispatch level and metered load drop. In its Final Root Cause Analysis, CAISO acknowledged that some demand response providers submitted baseline and meter data showing that baseline adjustments limited reported performance.[80] Many baseline methodologies use an average of the load levels from a number of days in the ten days prior to an event to calculate the resource's baseline, which may underestimate a resource's contribution compared to same-day methods, especially during high load periods like those seen during the events in 2020.[81] Even including same-day adjustments to a baseline to account for higher than average loads, a resource's load on an event day can be higher than its baseline from the previous ten days plus the adjustment, requiring a resource to reduce by as much as the difference between the day of load adjustment and the baseline, plus any amount below the baseline to show that it is reducing demand. CAISO is examining different counting methodologies for demand response to better capture its variable capability.[82]

CAISO, California PUC, and CEC also stated that some of the difference between demand response resources available and awarded may be due to physical and economic characteristics of resources as well as bidding practices that reduce the likelihood of resources being selected in the day-ahead market.[83] For example, the CAISO Department of Market Monitoring noted that even with energy prices reaching $1,000/MWh on critical days in summer 2020, a number of long-start demand response resources were not scheduled economically in the day-ahead market. As a result of not being selected in the day-ahead market, these resources were not required to participate in the residual unit commitment process, reducing the availability of resources in real-time due to their start-up time requirements. While resources are allowed to bid their own commitment costs as part of their offers, the CAISO Department of Market Monitoring noted that some demand response resources had commitment costs that made them uneconomic despite energy market bids that were lower than other resources. The CAISO Department of Market Monitoring recommended that CAISO consider what the appropriate commitment costs are for demand response resources as well as develop a process to manually dispatch PDR, which would allow resources to recover bid costs in excess of market revenues through bid cost recovery payments.[84] CAISO also stated that PDRs

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[79] *Id.* at 56, 108-109.

[80] Final Root Cause Analysis at 2.

[81] Recurve, *Regulatory and Measurement Barriers Hinder the Full Potential of Demand Response* (Jan. 12, 2021), https://www.recurve.com/blog/revenue-grade-analysis-of-the-ohmconnect-virtual-power-plant-during-the-california-blackouts; Greentech Media, *Seeking a Better Way to Pinpoint the Value of Demand Response in California* (Jan. 25, 2021), https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/seeking-a-better-way-to-pinpoint-the-value-of-demand-response-in-california.

[82] *Id.* at 3.

[83] *Id.*

[84] CAISO Department of Market Monitoring, *Report on Demand Response Issues and Performance* (Feb. 2021) at 12-14, http://www.caiso.com/Documents/ReportonDemandResponseIssuesandPerformance-Feb252021.pdf.

that under-perform are penalized at real-time 5-minute energy market prices, which are generally lower than day-ahead and 15-minute prices, reducing the incentive for demand response resources to perform.[85] As discussed in more detail in Chapter 5, CAISO implemented energy market enhancements to improve participation and dispatch of RDRRs in the energy market, which should increase their ability to respond to dispatch instructions. Incorporating some or all of these adjustments can positively impact the ability of demand response to participate in the real-time markets and improve their performance. CAISO has also taken other steps to address demand response participation and performance that are discussed in Chapters 4 and 5 of this report.

[85] Final Root Cause Analysis at 2.

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

Many regions use demand response to meet planning requirements in addition to its ability to reduce demand and meet changing system needs in the energy and ancillary services markets. This chapter reports on the potential for demand response as a quantifiable, reliable resource for regional planning purposes from the perspective of regulatory bodies, reliability coordinators, RTOs/ISOs and utilities.

NERC assessed the reliability of the bulk power system for the 2021 summer season. NERC noted that parts of North America are at an elevated risk of experiencing energy emergencies, which make grid operations more challenging through increased demand, increased outages, and lower resource output.[86] NERC recommended that balancing authorities and reliability coordinators conduct alert program drills to ensure preparation for conservation operations, LSEs prepare for demand-side conservation measures, and LSEs review non-firm customer inventories.[87] NERC separately noted that traditional resource adequacy methods at peak load times may not fully reflect the ability of resources in the current and coming resource mix, including demand response, to supply energy and reserves for all hours.[88] NERC further recommended that policy makers, system planners and other relevant parties review assessments and risks, and factor them into planning processes.[89]

In November 2019, the Public Utilities Commission of the State of California (California PUC) instituted a rulemaking to consider changes and refinements to the state's Resource Adequacy program, which included demand response. The California PUC's June 2021 proposed decision for the rulemaking requires multiple changes related to demand response for planning purposes. Historically, demand response resources were only required to be available Monday through Friday. In its proposed decision, the California PUC ordered demand response resources to increase availability to Monday through Saturday. The proposed decision observes that increasing availability helps ensure grid reliability, and notes that during the summer 2020 events, three of the highest load days were on weekends when 3,000 MW of demand response resources

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[86] North American Electric Reliability Corporation, *2021 Summer Reliability Assessment* (May 2021) at 4-5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf (NERC Summer Reliability Assessment). The regions that NERC identified as at an elevated risk are ERCOT, MISO, NPPC – New England, and WECC.

[87] *Id.* at 5.

[88] North American Electric Reliability Corporation, *2020 Long-Term Reliability Assessment* (Dec. 2020) at 9, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[89] NERC Summer Reliability Assessment at 5.

were not required to be available per availability rules at the time.[90] In addition, the California PUC's proposed decision for the 2022 Planning Year modifies the 15% Planning Reserve Margin adder for demand response resources in resource adequacy plans by removing the 6% associated with ancillary services. The proposed decision directs further study of the remaining 9% associated with load forecast error.[91] The proposed decision retains the Distribution Loss Factor and Transmission Loss Factor adders in its decision and instructs the California Energy Commission to consider whether to keep the Transmission Loss Factor beyond 2022.[92]

In July 2021, ERCOT developed a "Roadmap to Improving Grid Reliability" (Roadmap) intended to enhance operational reliability of the wholesale electric grid in Texas. The Roadmap contains 60 recommendations, four of which are related to demand-side management. Specifically, ERCOT's Roadmap proposes to improve the capability to manage short-supply situations, including additional voluntary load reductions; eliminate barriers to increase participation of distributed generation, energy storage, and demand response; perform testing of large industrial customers that are paid to reduce consumption during emergencies; and expand advanced meter implementation to receive more timely and accurate meter data for settlements and load management.[93]

PacifiCorp is an electric power company comprising two service territories: Pacific Power serves customers in California, Oregon, and Washington, while Rocky Mountain Power serves customers in Idaho, Utah, and Wyoming. To inform the planning process for its biennial Integrated Resource Plan, PacifiCorp commissioned a 20-year study to assess the cumulative potential for energy efficiency, demand response, and demand-side rates across its service territory from 2021 through 2040. The study identified few opportunities to expand PacifiCorp's summer demand response programs but highlights the potential for additional demand response from sources like battery storage, direct load control, grid-interactive water heaters, and third party contracts to reduce non-residential customer demand during system peak periods.[94] The study then assessed the potential for demand response to reduce demand over multiple hours (sustained duration) and for shorter duration events. The study identified the potential to add by 2040: (1) 1,300 MW of short duration demand response and 904 MW of sustained duration demand response during

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[90] *Before the Public Utilities Commission of the State of California, Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations*, Rulemaking 19-11-009, Decision 21-06-029 (California PUC June 24, 2021) at 20-21, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

[91] *Id.* at 41, 42.

[92] *Id.* at 43.

[93] ERCOT, *Roadmap to Improving Grid Reliability* (July 2021), http://www.ercot.com/content/wcm/lists/219694/ERCOT_Roadmap_Final_July_13_2021.pdf.

[94] PacifiCorp, *Conservation Potential Assessment for 2021-2040* (Feb. 2021) at viii, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/cpa-final-report-and-appendices/PacifiCorp%20DSM%20Potential%20Report%20-%20Vol%201%20-%20FINAL_2-26-2021.pdf.

the summer season; and (2) 1,322 MW of short duration demand response and 957 MW of sustained duration demand response during the winter season.[95] The summer and winter sustained duration totals represent increases of 296 MW and 498 MW, respectively, compared to the previous study.[96]

Southern Company and its subsidiaries, which serve over 9 million customers throughout the southeastern United States, have invested over $1 billion in energy efficiency and demand response since 2007. Southern Company estimates that these investments have translated to the ability to reduce peak demand by 5,600 MW, or 8%, resulting in the avoidance of 2,500 MW of new generation capacity.[97]

[95] *Id.* at 44, 45.

[96] *Id.* at 55.

[97] Southern Company, *Implementation and Action Toward Net Zero* (Sept. 2020) at 23, https://www.southerncompany.com/content/dam/southerncompany/pdfs/clean-energy/Net-zero-report.pdf.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter presents information on retail demand response[98] and dynamic pricing[99] programs based on EIA data. From 2018 to 2019, utilities reported significant increases in customer enrollment in both retail demand response and dynamic pricing programs. As more advanced meters are deployed across the country, data suggest that utilities continue to increase enrollments in programs designed to leverage advanced meter investments and customer participation in cost-saving programs. This chapter also summarizes recent federal, regional, state and industry actions and developments related to demand response.

Enrollment in Retail Demand Response and Dynamic Pricing Programs

As shown in Table 5-1 and Figure 5-1 below, nationwide customer enrollment in retail incentive-based demand response programs increased by over 1.1 million customers, or 12%, from 2018 to 2019. Regionally, customer enrollment increased in six Census Divisions, with utilities in five Census Divisions reporting aggregate annual increases of 20% or more. In absolute terms, utilities in the South Atlantic Census Division reported the greatest increase, with over 669,000 additional customers enrolled in retail incentive-based demand response programs. On a percentage basis, utilities in the West South Central Census Division reported the largest annual increase, 88%, in customer enrollment from 2018 to 2019. Utilities in the New England Census Division reported the second highest annual increase from 2018 to 2019 on a percentage basis, reporting a 43% increase in customer enrollment. Increases were also reported by utilities in the East North Central, Mountain, and West North Central Census Divisions.

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[98] Demand-side management (DSM) programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. Demand response programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. Previously, EIA referred to these programs as "incentive-based" demand response programs. *See* EIA, Form EIA-861S Instructions, Schedule 6 Part B, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; EIA, Form EIA-861 Instructions, Schedule 6 Part B, https://www.eia.gov/survey/form/eia_861/instructions.pdf; and FERC, *A National Assessment of Demand Response Potential* (2009), https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response.pdf.

[99] 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, 2018 Form EIA-861S Instructions, Schedule 6 Part C, https://www.eia.gov/electricity/data/eia861/.

Table 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2018 & 2019)

Census Division	Enrollment in Retail Demand Response Programs		Year-on-Year Change	
	2018	2019	Customers	%
East North Central	1,004,848	1,284,707	279,859	27.9%
East South Central	211,364	205,678	-5,686	-2.7%
Middle Atlantic	603,671	515,734	-87,937	-14.6%
Mountain	946,705	1,182,202	235,497	24.9%
New England	24,836	35,554	10,718	43.2%
Pacific	2,052,273	1,703,932	-348,341	-17.0%
South Atlantic	3,168,677	3,838,226	669,549	21.1%
West North Central	1,286,930	1,311,735	24,805	1.9%
West South Central	452,934	855,077	402,143	88.8%
Total	**9,752,238**	**10,932,845**	**1,180,607**	**12.1%**

Source: EIA, EIA-861 Demand_Response_2018, Utility_Data_2018, Demand_Response_2019, and Utility_Data_2019 data files.

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

Figure 5-1 below displays changes in customer enrollment from 2018 to 2019 by Census Division. Utilities in the South Atlantic Census Division continued to report the most customers enrolled in retail incentive-based demand response programs in 2019, with over 3.8 million customers. From 2018 to 2019, the largest increases in enrollment in the South Atlantic Census Division were reported by Baltimore Gas and Electric in Maryland, with 416,000 additional customers, and Duke Energy Carolinas in North Carolina and South Carolina, with a combined increase of over 244,000 customers. The increase in the West South Central Census Division, where utilities reported the largest percentage increase, is primarily attributable to an increase of 367,000 customers reported by the City of San Antonio, Texas. The largest increase in customers enrolled in the Mountain Census Division was reported by Public Service Company of Colorado, with additional enrollment of over 196,000 customers, while Commonwealth Edison in the East North Central Census Division reported an increase of over 332,000 customers.

Despite the large nationwide increase, not all Census Divisions realized growth in customer enrollment from 2018 to 2019. In aggregate, utilities in the Pacific Census Division reported the largest annual decrease, with 348,000 fewer customers enrolled in 2019 compared to 2018. However, individual utilities in the Pacific Census Division reported increases from 2018 to 2019, including San Diego Gas and Electric, which reported an additional 654,000 customers enrolled in incentive-based demand response programs, and Portland General Electric in Oregon, which reported an increase of 103,000 customers. The annual decrease in the Middle Atlantic Census Division is attributable to decreases in enrollment in programs run by Public Service Electric and Gas in New Jersey and Pennsylvania Power Company.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2018 and 2019)

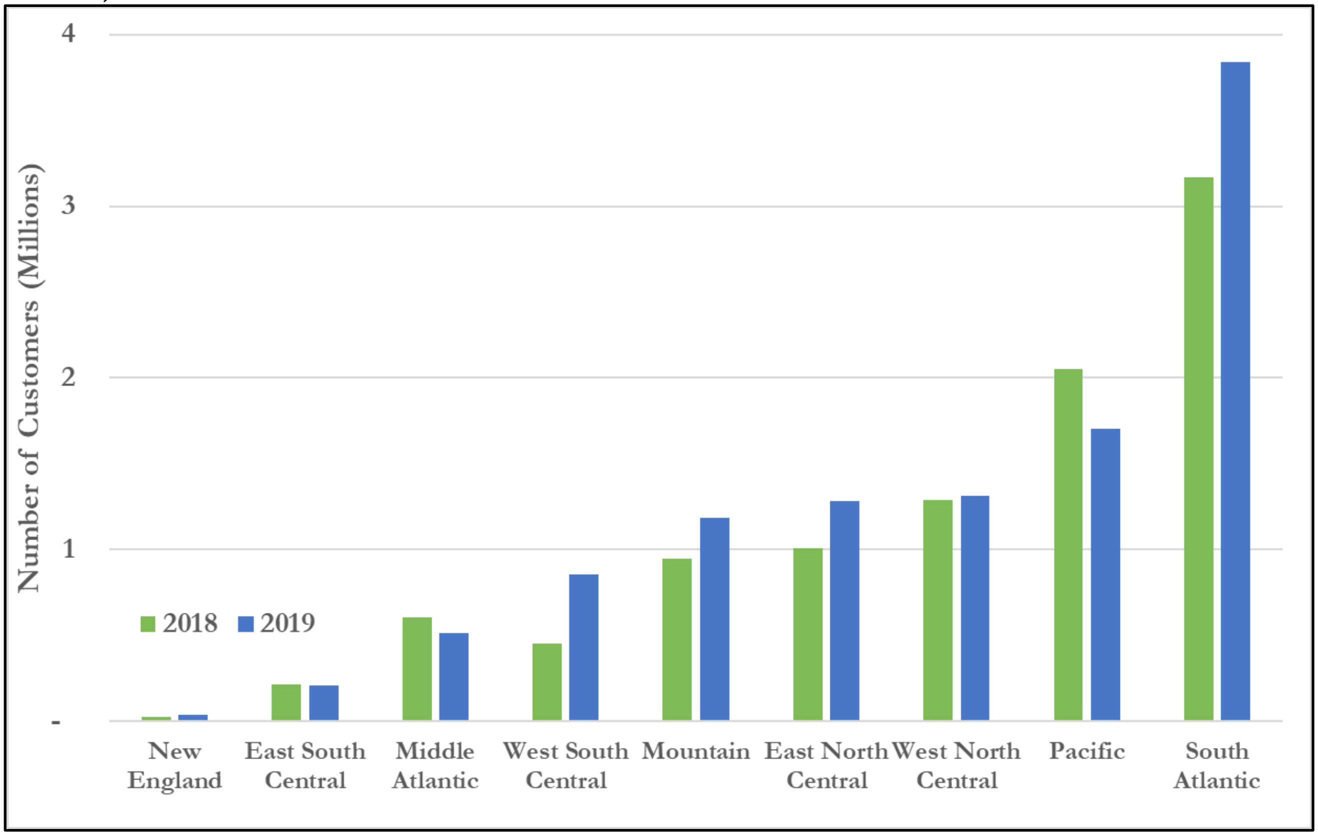


Table 5-2 below presents changes in customer enrollment in retail dynamic pricing programs by Census Division and shows a nationwide increase of over 1.7 million customers, or approximately 19%, from 2018 to 2019. While increases in enrollment in dynamic pricing programs were realized in eight of the nine regions, the increase was concentrated in the Pacific Census Division, where utilities reported the largest annual increase in both absolute and percentage terms. Approximately 36% of all customers enrolled in retail dynamic pricing programs in 2019 were enrolled in programs by utilities in the Pacific Census Division. The significant annual increase in enrollment in dynamic pricing programs in the Pacific Census Division coincides with the California PUC's 2015 decision requiring utilities to transition customers to default time-of-use rates beginning in 2018 and 2019.

Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 & 2019)

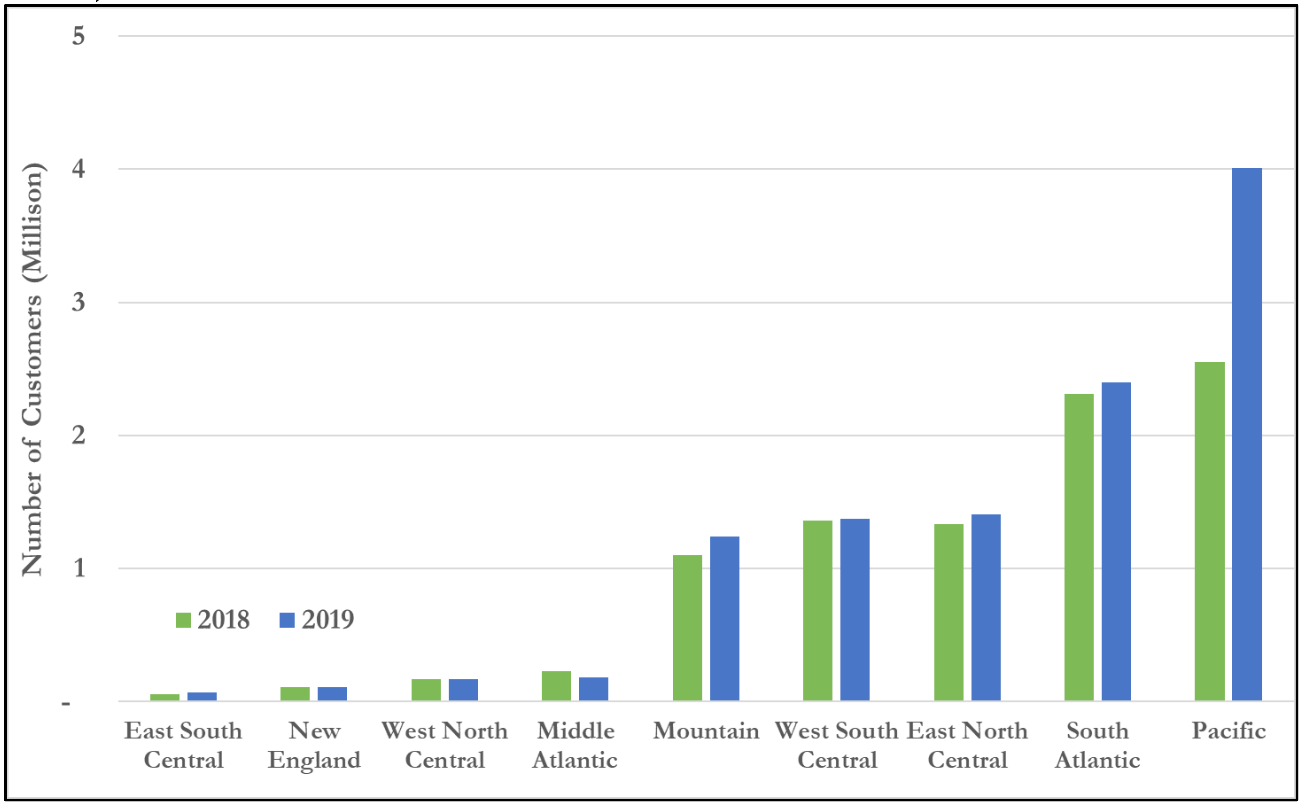
Census Division	Enrollment in Dynamic Pricing Programs		Year-on-Year Change	
	2018	2019	Customers	%
East North Central	1,331,303	1,406,404	75,101	5.6%
East South Central	58,536	70,380	11,844	20.2%
Middle Atlantic	230,980	179,692	-51,288	-22.2%
Mountain	1,098,450	1,237,492	139,042	12.7%
New England	106,896	110,242	3,346	3.1%
Pacific	2,551,339	4,009,490	1,458,151	57.2%
South Atlantic	2,309,385	2,400,027	90,642	3.9%
West North Central	170,013	172,144	2,131	1.3%
West South Central	1,362,967	1,372,452	9,485	0.7%
Total	**9,219,869**	**10,958,323**	**1,738,454**	**18.9%**

Source: Sources: EIA, EIA-861 Dynamic_Pricing _2018, Utility_Data_2018, Dynamic_Pricing_2019, and Dynamic_Pricing_2019 data files.

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

Figure 5-2 below shows that 2019 was the first year in which over 4 million customers were enrolled in retail dynamic pricing programs in a single Census Division, Pacific, as utilities in California began moving customers onto default time-of-use rates. Of the over 1.4 million additional customers enrolled from 2018 to 2019 in the Pacific Census Division, San Diego Gas and Electric reported more than 514,000 new customer enrollments, the Sacramento Municipal Utility District reported more than 461,000 new customer enrollments, and Pacific Gas and Electric reported more than 243,000 new customer enrollments. Utilities in other Census Divisions also reported increases in customer enrollment in dynamic pricing programs. From 2018 to 2019, Arizona Public Service Company in the Mountain Census Division reported an increase of over 55,000 customers while Ameren Illinois and Commonwealth Edison in the East North Central Census Division reported increases of over 32,000 customers and 26,000 customers.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 and 2019)



FERC Demand Response Orders and Activities

Order No. 2222 Rehearing Orders

On March 18, 2021, in Docket No. RM18-9-002, the Commission issued Order No. 2222-A. Order No. 2222-A largely affirmed Order No. 2222[100] but set aside the finding that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of Order Nos. 719 and 719-A.[101] The Commission declined to extend these opt-out provisions to demand response resources that participate in heterogeneous DER aggregations (i.e., different types of DERs participating in a single DER

[100] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 85 FR 67094 (Oct. 1, 2020), 172 FERC ¶ 61,247 (2020), *corrected*, 85 FR 68450 (Oct. 29, 2020), *order on reh'g*, Order No. 2222-A, 86 FR 16511 (Mar. 24, 2011), 174 FERC ¶ 61,197 (2021), *order on reh'g*, Order No. 2222-B, 86 FR 33853 (June 28, 2021), 175 FERC ¶ 61,227 (2021).

[101] Order Nos. 719 and 719-A opt-out provisions forbid grid operators from accepting offers from aggregated demand response where state and local regulators prohibit such participation.

aggregation). The Commission clarified that the opt-out provision does apply to aggregations solely made up of demand response.[102]

On June 17, 2021, in Docket No. RM18-9-003, the Commission issued Order No. 2222-B. Order No. 2222-B sets aside the Commission's decision in Order No. 2222-A that the opt-out requirement would not extend to aggregations that include a mix of demand response and other forms of DERs. Instead, the Commission will further evaluate whether to permit demand response resources to participate as part of a DER aggregation in the context of the Commission's broader Notice of Inquiry proceeding considering whether to revise its regulations to remove the demand response opt-out (discussed below).[103] Order No. 2222-B also provided further clarification regarding appropriate restrictions to avoid double counting of services and the compensation of demand response resources that participate in DER aggregations.

Participation of Aggregators of Retail Demand Response Customers in Markets Operated by RTOs/ISOs (Docket No. RM21-14-000)

On March 18, 2021, the Commission issued a Notice of Inquiry seeking comment on whether changing circumstances warrant revision to the demand response opt-out established in Order Nos. 719 and 719-A and whether RTO/ISO markets would significantly benefit from increased participation of demand response resources via aggregations in states that exercised the opt-out.[104] The order noted significant legal, policy and technological developments that warrant exploration of revision of the demand response opt-out. The order sought comment on the changed circumstances since the issuance of Order Nos. 719 and 719-A, potential benefits of removing the opt-out, and potential resulting burdens of removing the opt-out. Comments and reply comments were due in July and August 2021, respectively. The matter is currently pending before the Commission.

CAISO Summer 2021 Readiness Initiatives (Docket No. ER21-1536-000)

On May 25, 2021, the Commission accepted CAISO's tariff revisions that expand participation of RDRRs in the energy markets to prepare for summer 2021 in light of the supply shortages and market performance during the summer 2020 heat wave.[105] The revisions added 15-minute and hourly dispatch options that improve dispatch and pricing of RDRRs that were previously limited to CAISO's real-time market.[106] The added flexibility allows RDRRs to be included in the market optimization process and aims to avoid manual dispatch of these resources.[107]

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[102] Order No. 2222-A, 174 FERC ¶ 61,197 at P 22.

[103] Order No. 2222-B, 175 FERC ¶ 61,227 at P 26.

[104] *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198, at P 18 (2021).

[105] *Cal. Indep. Sys. Operator Corp.*, 175 FERC ¶ 61,160, at PP 35-36 (2021).

[106] CAISO, Filing, Docket No. ER21-1536-000, at 3 (filed Mar. 26, 2021).

[107] *Id.* at 36.

MISO Aggregator of Retail Customers Tariff Modifications (Docket No. ER20-2591-000)

On December 18, 2020, the Commission accepted MISO's tariff revisions to clarify Aggregator of Retail Customers (ARC) registration and participation provisions in MISO's energy and operating reserve markets.[108] According to MISO, ARCs are market participants that combine the abilities of one or more retail customers to provide load reductions or supply incremental energy through behind-the-meter generation.[109] The revisions clarify the requirements for ARCs to register as Demand Response Resources, Emergency Demand Response, and/or Load Modifying Resources, subject to participation being allowed, either explicitly or implicitly, by the Relevant Electric Retail Regulatory Authority.[110] The revisions require ARC applicants to provide their maximum level of participation and allow MISO to deny applications that include end-use customers included in an existing resource to prevent double counting, unless the end-use customer(s) operate under special rate structures and is not registered as part of any MISO resources.[111]

MISO LMR Performance Evaluation (Docket No. ER21-693-000)

On February 3, 2021, the Commission issued an order accepting MISO's revisions to clarify the performance evaluation provisions for LMRs.[112] MISO filed revisions to clarify that a market participant shall at all times notify MISO when the status or availability of an LMR changes and to clarify that an LMR that fails to perform in accordance with its market participant's response to MISO's scheduling instruction will be subject to a penalty and will not receive credit for its deployment with respect to the required annual availability.[113]

NYISO Buyer-Side Market Power Mitigation Rules for Special Case Resources (Docket Nos. EL16-92-001 and EL16-92-003)

On February 18, 2021, the Commission set aside in part its October 2020 order and found that Commercial System Distribution Load Relief Programs (CSRP) should be excluded from the calculation of Special Case Resource (SCR) offer floors.[114] The Commission found that CSRPs are designed to benefit the distribution system and not system-wide needs, and any system-wide reliability benefit provided by CSRPs are not the result of the programs' design.[115] SCRs are demand response resources that can provide capacity in

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[108] *Midcontinent Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,254, at P 1 (2020).

[109] *Id.* (citing Transmittal at 1).

[110] *Id.* P 4.

[111] *Id.* PP 4, 47.

[112] *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER21-693-000 (Feb. 3, 2021) (delegated order).

[113] MISO, Filing, Docket No. ER21-693-000, at 4 (filed Dec. 21, 2020). *See* MISO FERC Electric Tariff Section 69A.3.3.1, Deployment Procedures for LMR, 34.0.0. A.

[114] *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110, at PP 2, 10 (2021).

[115] *Id.* PP 11-12.

NYISO's capacity market. In 2016, a complaint was filed against NYISO alleging that the application of its buyer-side market power mitigation rules are unjust and unreasonable because they limit full participation of SCRs in NYISO's capacity market and interfere with federal, state, and local policy objectives.[116] Complainants requested that the Commission establish a blanket exemption for SCRs from NYISO's buyer-side market power mitigation rules or exclude payments received from certain retail-level demand response programs from the calculations of SCRs' offer floors. On October 7, 2020, the Commission concluded that payments received under the CSRP did not qualify for exclusion from offer floor calculation for SCR under NYISO's buyer-side market power mitigation rules.[117] In December 2020, requests for rehearing of that October 7, 2020 order were denied by operation of law.[118]

Other Federal Demand Response Activities

Department of Defense

The U.S. Department of Defense (DoD) Defense Logistics Agency Energy (DLA Energy) provides the DoD and other federal government agencies with comprehensive energy solutions,[119] including administering incentive-based demand response programs. In fiscal year 2020, DLA Energy coordinated and facilitated the participation of 46 installations in demand response programs in 11 states and the District of Columbia—all of which are within organized wholesale markets—and had 93 MW of demand response enrolled in its programs.[120] DLA Energy reported savings of over $2.7 million in fiscal year 2020, with cumulative savings since 2008 totaling over $39 million.

Energy Act of 2020

As part of the omnibus appropriations bill signed into law on December 27, 2020, Congress passed the Energy Act of 2020.[121] Section 1002 of the act amended the National Energy Conservation Policy Act and requires that agencies report the status of energy savings performance contracts, the investment value of the contracts, and a comparison of guaranteed savings to actual energy savings.[122] Section 1007 of the act

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[116] New York PSC, Complaint, Docket No. EL16-92-000 (filed June 24, 2016).

[117] *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 174 FERC ¶ 61,110, at P 1 (2020) (citing *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,022, at PP 4, 57-58 (2020)).

[118] *N.Y. Pub. Serv. Comm'n v. N.Y. Indep. Sys. Operator, Inc.*, 173 FERC ¶ 62,125 (2020).

[119] Department of Defense, *Defense Logistics Agency Energy, Fiscal Year 2020 Fact Book* (Jan. 2020) at 2, https://www.dla.mil/Portals/104/Documents/Energy/Publications/DLAEnergyFactBookFY20_lowres2.pdf?ver=VE-mCUImzFiKKnG1uajkxg%3D%3D.

[120] *Id.* at 49.

[121] House Committee on Rules and Senate Committee on Energy & Natural Resources, *Rules Committee Print 116-68 Text of the House Amendment to the Senate Amendment to H.R.* (Dec. 21, 2020), https://rules.house.gov/sites/democrats.rules.house.gov/files/BILLS-116HR133SA-RCP-116-68.pdf.

[122] *Id.* at 734-35.

requires that the Secretary of Energy enact the Federal Smart Building Program to implement smart building technologies in and across multiple agencies to increase building energy savings and to advance integration of buildings onto the electric grid to serve as resources and dynamic energy loads.[123] The requirement includes the development of data management capabilities, standard communication protocols for interoperability at the building and grid level, and development of advanced building energy management through integration of smart technologies, control systems, and data processing to enable energy efficiency and savings.[124] The act requires that the Secretary of Energy "carry out research, development, demonstration, and commercialization activities" in many subject areas, including demand response technologies.[125]

General Services Administration

The General Services Administration (GSA) manages centralized procurement for the Federal government, which includes providing energy services for agency workspaces in buildings that are either federally-owned or leased.[126] In July 2020, the GSA's Green Building Advisory Committee released its proposed roadmap and advice letter to review and modify federal energy policy goals, which currently focus on energy reduction, to include load management, demand reduction, flexible rate structures, and exploration of pilot programs to better realize demand savings.[127] The proposed roadmap discusses conducting a comprehensive review of federal agency outleasing authorities to identify where this approach is feasible; conducting a comprehensive review of GSA's owned portfolio to determine which assets are conducive to solar outleasing based on the criteria identified by the GSA; researching the costs, benefits, and logistics of integrating federal renewable outleases into GSA's outleasing program; learning from the experience of state and local governments; developing resources to support renewable energy outleasing, including standardized processes and documentation for identifying underutilized assets; soliciting competitive proposals for renewable leasing; and testing the renewable energy outleasing concept with a pilot project for an asset or assets conducive to solar outleasing.[128]

Grid-Interactive Efficient Buildings

In May 2021, the DOE and Lawrence Berkeley National Laboratory published a roadmap that detailed the potential for grid-interactive efficient buildings (GEB) to deliver $100 to $200 billion in cumulative electric

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[123] *Id.* at 773-74.

[124] *Id.* at 771-72.

[125] *Id.* at 948.

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

[127] GSA, *GSA Green Building Advisory Committee Advice Letter on Renewable Energy Outleasing* (Jul. 2020) at 2, https://www.gsa.gov/cdnstatic/FINAL_REO_TG_Advice_Ltr_7-9-20_-_508.pdf.

[128] *Id.* at 8.

system costs savings through 2040.[129] GEBs are energy efficient buildings that use smart technologies and DERs to optimize energy use for grid services, occupant needs and cost reductions.[130] The DOE and Lawrence Berkeley National Laboratory found that GEBs can provide value to the grid through energy efficiency measures, load shedding, load shifting, ancillary services and electricity generation.[131] The study noted that, currently, approximately 10 GW of peak demand reduction capability from technology-enabled demand flexibility is available in residential and commercial buildings.[132] The report identified an additional 15.6 GW of new, dispatchable demand flexibility from residential and commercial programs scheduled to come online by 2030.[133] In addition, the report noted the opportunity for building-integrated DERs to increase the value of GEBs. For example, optimizing building-integrated solar production with building loads and interoperability between DER communications and controls can unlock greater value from GEBs.[134] Finally, the report noted that incentive-based and price-based utility program offerings can provide financial incentives for GEB deployment, while incorporating demand flexibility into utility planning can reduce supply-side investment.[135]

Infrastructure Investment and Jobs Act

On November 15, 2021, President Biden signed the Infrastructure Investment and Jobs Act (the Act), which contains amendments to previous energy legislation and investments for energy infrastructure, some of which are related to demand response resources and advanced metering. Section 40104 of the Act amends the Public Utility Regulatory Policies Act of 1976 by directing electric utilities to promote the use of demand response and demand flexibility practices by commercial, residential and industrial consumers to reduce electricity consumption during periods of unusually high demand.[136] The Act also requires state regulatory authorities to consider rate mechanisms that allow for cost recovery and requires that each state regulatory authority commence consideration or set a hearing date for consideration within one year of enactment and make a determination within two years of enactment to establish mechanisms to recover the costs of promoting demand response and demand flexibility practices.[137] The Act also amends the Federal

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[129] U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, *A National Roadmap for Grid-Interactive Efficient Buildings* (May 2021) at 1, https://gebroadmap.lbl.gov/A%20National%20Roadmap%20for%20GEBs-20210712.pdf.

[130] *Id.* at 3, 5.

[131] *Id.* at 4.

[132] *Id.* at 10.

[133] *Id.* at 12.

[134] *Id.* at 25-26.

[135] *Id.* at 36.

[136] Infrastructure Investment and Jobs Act of 2021, Pub. L. No. 117-58, § 40104, 125 Stat. 429, 502-503 (2021), https://www.congress.gov/117/bills/hr3684/BILLS-117hr3684enr.pdf.

[137] *Id.* at 503-504.

Energy Management Program to promote installation of demand response technology and the use of demand response practices in Federal buildings.[138] Additionally, the Act amends the Energy Independence and Security Act of 2007 to include demand response technologies, practices, and policies as part of the Components of Zero-Net-Energy Commercial Buildings Initiative.[139] Section 40125 of the Act requires development of advanced cybersecurity applications and technologies for the energy sector to identify and mitigate vulnerabilities and specifically discusses the need to advance the security of field devices and third-party control systems, including advanced metering.[140] Section 40413 of the Act expands the Manufacturing Energy Consumption Survey to collect information on the use of demand response.[141] Finally, Section 40417 of the Act requires development of a plan to identify the need or opportunity to update or further the capabilities of the National Energy Modeling System with respect to demand response in capacity expansion models and the economic modeling of the role of demand response.[142]

Developments and Issues in Demand Response

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

State regulators and policymakers continue to expand dynamic pricing offerings through pilot programs and permanent rate programs. Orders issued by state regulators, such as those in Illinois and North Carolina, stress the importance of clear price signals to induce customer behavior to use less power depending on the time of day. Similarly, state policymakers in states like Indiana and Montana passed legislation seeking to further study the benefits of dynamic pricing.

- **California.** On November 20, 2020, the California PUC instituted a rulemaking to identify and execute interim and longer-term actions to ensure reliable electric service in the event of an extreme heat storm in the summer of 2021.[143] In March 2021, for the summers of 2021 and 2022, the California PUC directed the state's major investor-owned utilities to take specific actions to decrease peak and net peak demand[144] and increase supply to avoid rotating outages similar to the events that

[138] *Id.* at 505.

[139] *Id.* at 505.

[140] *Id.* at 527.

[141] *Id.* at 614.

[142] *Id.* at 617.

[143] *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021*, Rulemaking 20-11-003 (California PUC Nov. 20, 2020) at 2, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M351/K809/351809897.PDF.

[144] Net Peak Demand, also known as "net peak" or "net demand", is defined by the California Energy Commission as the "total electricity demand minus utility-scale solar and wind generation at a given

occurred in summer 2020.[145] The March 2021 decision required Pacific Gas & Electric and San Diego Gas & Electric to increase critical peak pricing event windows from 4 pm to 9 pm, while Southern California Edison was required to increase the number of events from 12 to 15.[146] The decision also required utilities to develop and administer a pilot Emergency Load Reduction Program to access additional load reduction outside of the resource adequacy framework during times of grid stress and emergency, notably from non-residential customers not already in demand response programs and some proxy demand resources.[147] The pilot program will require resources to be available May through October, seven days a week during the evening peak, for a minimum of one hour and maximum of five hours following a CAISO Alert, Warning, or Emergency declaration.[148] In a June 2021 decision, the California PUC modified its original decision and clarified that the Emergency Load Reduction Program would have day-ahead and day-of triggers for a subset of the program's resources.[149] The pilot programs are for five years, with the years 2023 through 2025 subject to revision in a later proceeding.

In July 2021, the California PUC issued an order instituting a rulemaking to prepare the electric grid for a high number of DERs, including demand response.[150] The California PUC noted that the expected growth of DERs, electric vehicles and higher clean energy goals and emissions targets,

time, and… typically occurs later in the evening than the total demand peak." California Energy Commission, *A Peek at Net Peak* (May 2021), https://www.energy.ca.gov/data-reports/energy-insights/peek-net-peak.

[145] *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, Rulemaking 20-11-003 (California PUC Mar. 5, 2021) at 5, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286360.PDF.

[146] *Decision Directing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Take Actions to Prepare for Potential Extreme Weather in the Summers of 2021 and 2022*, Rulemaking 20-11-003 (California PUC Mar. 5, 2021) Att. 1 at 2, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K237/369237342.PDF.

[147] *Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021*, Rulemaking 20-11-003 (California PUC Mar. 5, 2021) at 15-16, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M369/K286/369286360.PDF.

[148] *Id.* at 17.

[149] *Order Modifying Decision 21-03-056 to Clarify Guidance in the Emergency Load Reduction Program Regarding a Day-Of Trigger*, Rulemaking 20-11-003 (California PUC June 25, 2021) at 1, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K525/389525818.PDF.

[150] *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Rulemaking 21-06-017 (California PUC July 2, 2021) at 1, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

highlighted the need to explore improvements to distribution planning and grid modernization.[151] The California PUC held a workshop in September 2021 and issued a preliminary schedule that included a scoping memo and ruling date of late 2021 with a proposed decision date of 2024.[152]

- **Illinois.** On April 1, 2020, the Illinois Commerce Commission issued an order on rehearing to implement changes to the Commonwealth Edison Company's (ComEd) residential time-of-use rate pilot program to incentivize residential customers to shift their energy use away from peak periods.[153] The Illinois Commerce Commission stated that ComEd's proposal, as requested on rehearing, does not provide a clear price signal for customers to switch usage to avoid high energy prices.[154] In the order, the Illinois Commerce Commission directed ComEd to file its new pilot time-of-use rates to encourage customers to alter their usage patterns under clearly stated times and clear price differentiation.[155] On April 12, 2021, ComEd filed its latest time-of-use pricing pilot report, required to be submitted semiannually in compliance with the order.[156]

- **Indiana**. On April 26, 2021, the governor of Indiana signed a bill that reestablished the state's 21st Century Energy Policy Development Task Force following its expiration on December 2, 2020.[157] The law requires that the Task Force study a number of issues, including methods to assure fairness to customers on time-of-use, real-time pricing, and critical peak pricing rate designs; appropriate regulation of the deployment of DERs consistent with Order No. 2222; and demand response and pricing systems that incentivize temporal shifting of electric load.[158] The law requires that the Task Force develop recommendations and issue a report for the General Assembly and the governor by November 1, 2022.[159]

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

[152] *Id.* at 27.

[153] *Verified Petition for Approval of a Revision to Integrated Distribution Company Implementation Plan*, Docket No. 18-1725 (Illinois Commerce Commission Apr. 17, 2021) at 1, https://www.icc.illinois.gov/docket/P2018-1725/documents/298022/files/519662.pdf.

[154] *Id.* at 27-28.

[155] *Id.* at 28-30.

[156] *Verified Petition for Approval of a Revision to Integrated Distribution Company Implementation Plan*, Compliance Filing #2, Docket No. 18-1725 (Illinois Commerce Commission Apr. 12, 2021), https://www.icc.illinois.gov/docket/P2018-1725/documents/310325/files/540776.pdf.

[157] 21st Century Energy Policy Development Task Force, Ind. Legis. Serv. P.L. 131-2021 (H.E.A. 1220), Ind. Code Ann. § 2-5-45.1 (2021), http://184.175.130.101/legislative/2021/bills/house/1220#document-066c3967.

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

[159] *Id.* at 2.

- **Minnesota**. On May 25, 2021, the governor of Minnesota signed the Energy Conservation and Optimization Act of 2021, which found that energy savings are an energy resource and that optimizing the timing and method used by energy consumers to manage energy use provides benefits to customers and the utility system as a whole.[160] The law requires the state to achieve annual energy savings equal to at least 2.5% of annual retail energy sales of electricity and natural gas. The law defines load management as an activity, service, or technology that changes the timing or efficiency of a customer's use based on local and regional energy system conditions or to reduce peak demand and stated that utilities can meet the goal through rate designs, programs to change consumer behavior, efforts to promote energy conservation, and load management programs that enable customers to maximize the value of energy purchased.[161] The law also requires that, by June 1, 2022, and every three years thereafter, each of the state's cooperative and municipal electric utilities file an energy conservation and optimization plan describing load management and other measures intended to achieve the law's energy savings goals.[162]

- **Montana.** As discussed above,[163] on May 12, 2021, the Montana legislature passed a joint resolution requesting an interim study to examine future electric grid capacity requirements, grid technologies, and the roles of regulatory, private-sector, and state government entities in the future of the grid.[164] Specifically, the resolution designates an interim committee to study, among other things, the impact of future electricity load that may drive future capacity requirements and "the contributions of non-generation technologies to achieve a more efficient, lower-peak grid." The legislature directed that the study be completed prior to September 15, 2022.

- **New York**. On May 14, 2020, the New York PSC ordered the state's six investor-owned utilities to file emergency tariff modifications to make program changes for the 2020 summer demand response Capability Period for capacity.[165] The changes provided additional flexibility for demand response market participants by extending program enrollment deadlines in response to the declared state disaster emergency resulting from COVID-19.[166] Utilities submitted compliance filings at the end of

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[160] Energy Conservation and Optimization Act of 2021, HF 164, 92nd Minnesota Legislature (2021) at 1-2, http://wdoc.house.leg.state.mn.us/leg/LS92/HF0164.2.pdf.

[161] *Id.* at 2, 5.

[162] *Id.* at 7.

[163] *See supra* Ch. 2.

[164] *Id.*

[165] *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, Case No. 14-E-0423 (New York PSC Apr. 16, 2021) at 1-2, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4D9D4832-9854-4C7F-9DA6-350A70F86CD3}.

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

May 2020. In August 2020, the New York PSC made its May 2020 emergency order permanent.[167] In April 2021, the New York PSC extended the provision in response to stakeholder requests to allow for adjustments in enrolled capability by June 1, 2021 for the 2021 Capability Period.[168]

- **North Carolina.** On May 7, 2021, Duke Energy Carolinas filed a petition requesting that the North Carolina Utilities Commission (North Carolina Commission) approve critical peak pricing schedules.[169] The petition stated that the dynamic rate pilots approved by the North Carolina Commission demonstrated customer potential to change their consumption patterns in response to price signals and created savings and system benefits.[170] According to Duke Energy Carolinas, lessons learned and data from pilot programs were incorporated into its most recent petition to implement the new offerings.[171] As the North Carolina Commission considers the petition, the current advanced rate pilots will be extended until issuance of a further order.[172]

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[167] *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, Case No. 14-E-0423 (New York PSC Aug. 7, 2020) at 3, https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-E-0423.

[168] *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, Case No. 14-E-0423 (New York PSC Apr. 16, 2021) at 12, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4D9D4832-9854-4C7F-9DA6-350A70F86CD3}.

[169] *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1253 (North Carolina Commission May 7, 2021) at 1, https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=3d73c0a1-aae9-480c-b96f-10aaae7ddf1d.

[170] *Id.* at 3.

[171] *Id.* at 3.

[172] *Id.* at 2.

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

Even as the number of customers participating in demand response programs grows, regulatory barriers to customer participation continue to exist. With new streams of resources, customer information, and program data, regulators and utilities must consider the best way to use investments to improve customer participation in and satisfaction with demand response programs. Outstanding barriers to customer participation and recommendations are discussed below.

Implementing Time-Based Rates

The total number of customers enrolled in retail dynamic pricing and retail demand response programs is still relatively low compared to the total number of retail customers in the United States. Advanced metering facilitates demand-side strategies, and demand response programs increase demand-side customer engagement, which results in lower energy costs for customers and deferred generation. Regulatory approval processes required for technologies that unlock the value of demand response and time-based rate programs, like advanced metering, can slow the development and implementation of new programs. For example, regulators can require utilities to demonstrate how advanced metering will not only unlock the potential for demand reduction strategies, but also help achieve other state goals. Lengthy regulatory proceedings can delay adoption of new technologies and programs despite the growth of advanced metering and its abilities. Similarly, even previously approved and successful pilot programs face regulatory barriers that limit customer participation, delaying or eliminating benefits to customers.

Incorporating Demand Flexibility

The number of customer-sited DERs, smart technologies, and flexible loads in the United States continues to grow. Demand flexibility, also known as load flexibility, is the capability of loads and customer-sited DERs coupled with smart technologies and controls to change load patterns or generate electricity. As described in Chapter 5, recent analysis from the Department of Energy shows that demand flexibility through use of smart buildings like GEBs and Connected Communities can deliver billions of dollars in electric system savings.

A recent Department of Energy report indicates that barriers to adopting and using the full suite of capabilities of demand-side resources prevents consumers, regulators, and utilities from realizing the full potential of those resources.[173] For example, many RTO/ISO markets limit the ability of demand flexibility to participate at the wholesale level as demand response because demand response is often defined as a reduction in expected consumption. Demand flexibility can also require coordinated operation of multiple devices or buildings to achieve full savings. The costs to adopt all the technological components required to achieve maximum demand flexibility, and the greater interoperability requirements, may currently inhibit the

[173] U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, *A National Roadmap for Grid-Interactive Efficient Buildings* (May 2021) at 27, https://gebroadmap.lbl.gov/A%20National%20Roadmap%20for%20GEBs-20210712.pdf.

deployment of these resources. While some RTOs/ISOs incorporate demand response and demand-side resources into planning and resource adequacy processes, the full suite of demand flexibility capabilities are not currently accounted for in utility, state, and RTO/ISO planning processes. DOE argues that support in state, local, and federal policies and regulatory proceedings is critical to broader adoption and utilization of demand flexibility.[174]

[174] *Id.* at 29.

Appendix: List and Map of Census Divisions

The 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

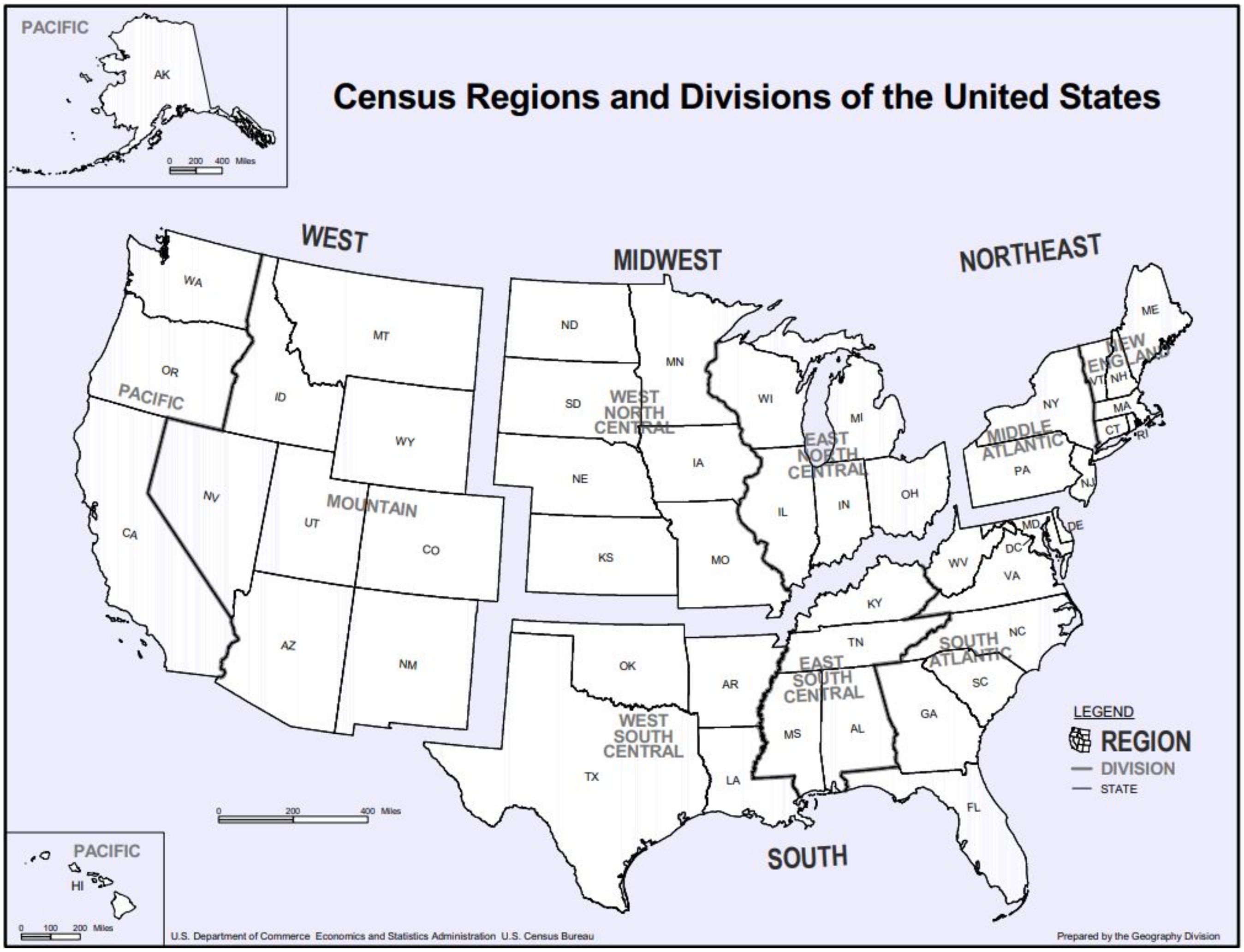
Division 5, South Atlantic: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia

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
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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
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LEGEND
REGION
DIVISION
STATE
U.S. Department of Commerce Economics and Statistics Administration U.S. Census Bureau
Prepared by the Geography Division

2021 Assessment of

Demand Response and Advanced Metering

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