2022 Assessment of

Demand Response and Advanced Metering

Staff Report

Federal Energy Regulatory Commission

December 2022

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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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December 2022

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.

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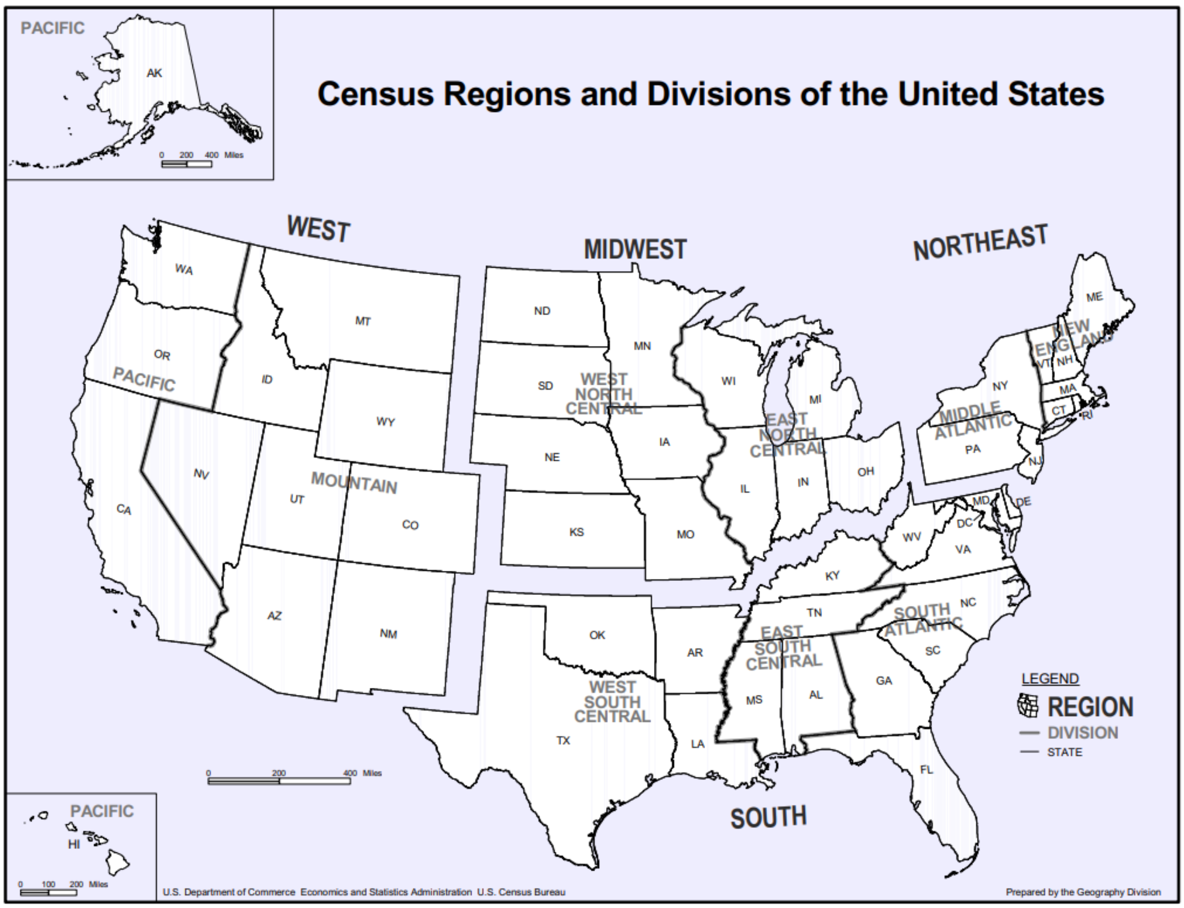
1. Introduction

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

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

Figure 1-1: Map of US Census Divisions



[1] The latest publicly available retail data for the report is for the year 2020 while the latest publicly available wholesale data is for the year 2021.

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

Highlights of this report include the following:

- From 2019 to 2020, the number of advanced meters[3] in operation in the United States increased by 8.3 million to a total of 103.1 million, representing an 8.8% annual increase. According to Energy Information Administration (EIA) data, the 103.1 million advanced meters in operation represent over 64% of the 159.7 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 2020.

- In 2020, utilities in the South Atlantic Census Division reported over 23 million advanced meters in operation, while utilities in the East North Central, Pacific, and West South Central Census Divisions each reported over 16 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 70%.

- State regulators continue to consider and approve proposals to deploy advanced meters, often as a component of larger grid modernization plans. Regulators in Massachusetts, Ohio, and Virginia are all either actively considering, or have recently approved, advanced meter deployments through grid modernization proceedings. Additionally, California regulators directed utilities in the state to implement certain communication protocols to facilitate the submetering of electric vehicles (EVs) through electric vehicle supply equipment (EVSE).

- From 2020 to 2021, demand resource totals increased in the wholesale markets by approximately 1,833 MW to a total of 32,421 MW, representing a 6% annual increase. Demand resource totals increased from 2020 to 2021 in all but one of the wholesale markets.

- From 2019 to 2020, customer enrollment in retail dynamic pricing programs increased by 1.2 million, and customer enrollment in retail incentive-based demand response programs increased by over 732,000. These customer enrollment increases represent annual percentage increases of 11.3% and 6.7%, respectively.

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[3] As defined by EIA, advanced metering infrastructure (AMI) meters (also referred to throughout this report as "advanced meters") are "[m]eters that measure and record data[,] at a minimum, in hourly intervals and provide usage data at least daily to energy companies and may also provide data to consumers. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data."

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

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

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems (Chapter 2);

(B) existing demand response and time-based rate programs (Chapter 5);

(C) the annual resource contribution of demand resources (Chapter 3);

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes (Chapter 4);

(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party (Chapter 5); and

(F) regulatory barriers to improved customer participation in demand response, peak reduction, and critical period pricing programs (Chapter 6).

2. Saturation and Penetration Rate of Advanced Meters

This chapter presents the national and regional penetration rates for advanced meters as well as state developments related to grid modernization and advanced metering. Table 2-1 shows estimates of advanced meter penetration rates from 2007 through 2020. According to EIA data, there were 103.1 million advanced meters installed and operational out of 159.7 million total meters in the United States in 2020, representing an advanced meter penetration rate of 64.6%. This also represents an increase of 8.3 million advanced meters, or 8.8%, from 2019 to 2020. The Edison Foundation's Institute for Electric Innovation reported a similar number of advanced meters for 2020, reporting approximately 107.4 million advanced meters in operation in the United States.

Table 2-1: Estimates of Advanced Meter Penetration Rates

Data Source	Data as Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration 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%
2012 Form EIA-861[5]	Dec 2012 (EIA)	43.2	145.3	29.7%
2013 Form EIA-861[6]	Dec 2013 (EIA)	51.9	138.1	37.6%
2014 Form EIA-861[7]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[8]	Dec 2015 (EIA)	64.7	150.8	42.9%
2016 Form EIA-861[9]	Dec 2016 (EIA)	70.8	151.3	46.8%
2017 Form EIA-861[10]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[11]	Dec 2018 (EIA)	86.8	154.1	56.4%
2019 Form EIA-861[12]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[13]	Dec 2019 (IEI)	99.0	157.2	63.0%
2020 Form EIA-861[14]	Dec 2020 (EIA)	103.1	159.7	64.6%
Institute for Electric Innovation[15]	Dec 2020 (IEI)	107.4	159.7	67.2%

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] EIA-861 and EIA-861S: retail_sales_2012 and advanced_meters_2012 data files (Oct. 29, 2013). [6] 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. [7] EIA-861: Advanced_Meters_2014 data file (re-released Jan. 13, 2016). [8] EIA-861: Advanced_Meters_2015 data file (re-released Nov. 1, 2016). [9] EIA-861: Advanced_Meters_2016 data file (re-released Nov. 6, 2017). [10] EIA-861: Advanced_Meters_2017 data file (re-released Jan. 15, 2019). [11] EIA-861: Advanced_Meters_2018 data file (originally released October 2019, re-released Mar. 16, 2020). [12] EIA-861: Advanced_Meters_2019 data file (released Oct. 6, 2020). [13] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2021). [14] EIA-861: Advanced_Meters_2020 data file (released Oct. 7, 2021). [15] IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* (2021). The IEI report provides only projections for the total number of advanced meters for 2020.

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

Figure 2-1 displays advanced meter growth in the United States from 2007 through 2020. Since 2007, the number of advanced meters in operation has increased by 96.4 million, from 6.7 million meters in 2007 to approximately 103.1 million meters in 2020. Advanced meters are the most prevalent meter type in the United States, with the advanced meter penetration rate increasing from 60.3% in 2019 to 64.6% in 2020. EIA data show that the number of advanced meters increased by approximately 8.3 million, or 8.8%, from 2019 to 2020. This represents the fourth consecutive year that the number of advanced meters has increased by approximately 8 million.

Figure 2-1: Advanced Meter Growth (2007–2020)

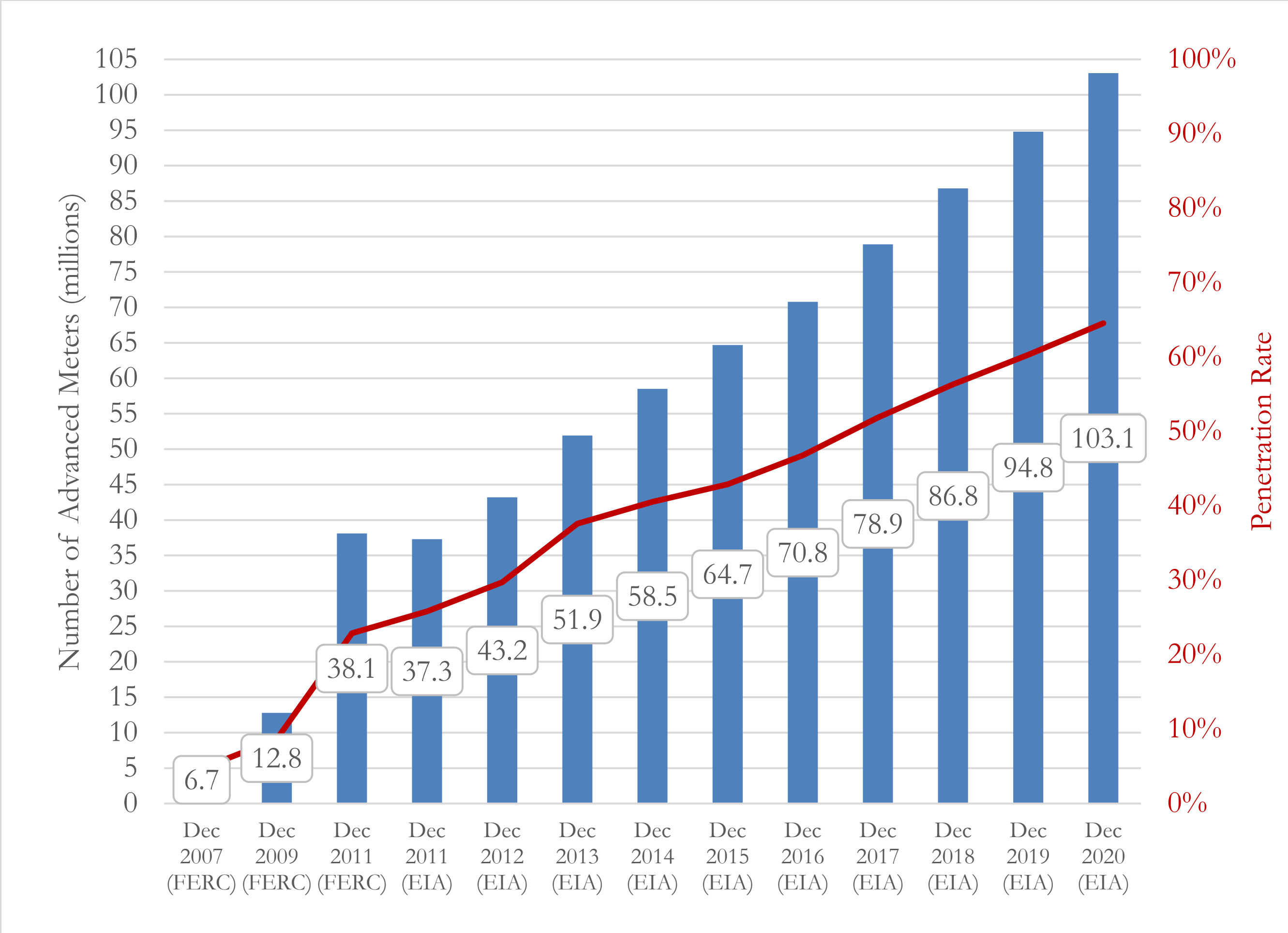


Table 2-2 below provides estimates of advanced meter penetration rates by Census Division and retail customer class for 2020. Utilities reported aggregate totals of advanced meters that represent penetration rates above 70% in five of the Census Divisions. As shown in Table 2-2, utilities in the West South Central Census Division reported advanced meter totals that represent an advanced meter penetration rate of 81.4%, the highest advanced meter penetration rate reported by utilities in any Census Division. In contrast, utilities in the Middle Atlantic, New England, and West North Central Census Divisions reported totals representing aggregate advanced meter penetration rates below 50%.

Table 2-2 also shows the overall advanced meter penetration rate for the residential, commercial, and industrial customer classes. For the third consecutive year, the advanced meter penetration rate for each of the customer classes across all Census Divisions was greater than 50%. However, the advanced meter penetration rates for each customer class varied between Census Divisions. For example, in six of the nine Census Divisions the residential customer class had the highest advanced meter penetration rates, while in three Census Divisions the highest advanced meter penetration rates were in the industrial customer class. Utilities reported the highest number of advanced meters in the residential class, which represented a penetration rate of 65.0%. The reported totals for the commercial and industrial customer classes followed closely, which represented advanced meter penetration rates of 61.6% and 58.1%, respectively.

Table 2-2: Advanced Meter Penetration Rate by Census Division and Customer Class (2020)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	71.7%	67.1%	57.2%	71.1%
East South Central	75.8%	68.3%	54.2%	74.7%
Middle Atlantic	40.2%	35.6%	41.6%	39.7%
Mountain	54.0%	51.0%	53.8%	53.6%
New England	23.0%	25.0%	26.0%	23.3%
Pacific	76.1%	75.6%	61.2%	75.9%
South Atlantic	72.2%	67.8%	59.3%	71.6%
West North Central	48.1%	47.3%	63.5%	48.2%
West South Central	82.1%	78.1%	61.5%	81.4%
All Regions	**65.0%**	**61.6%**	**58.1%**	**64.5%**

Source: 2020 Form EIA-861 Advanced_Meters_2020 data file and 2020 Form EIA-861 Utility_Data_2020 data file.

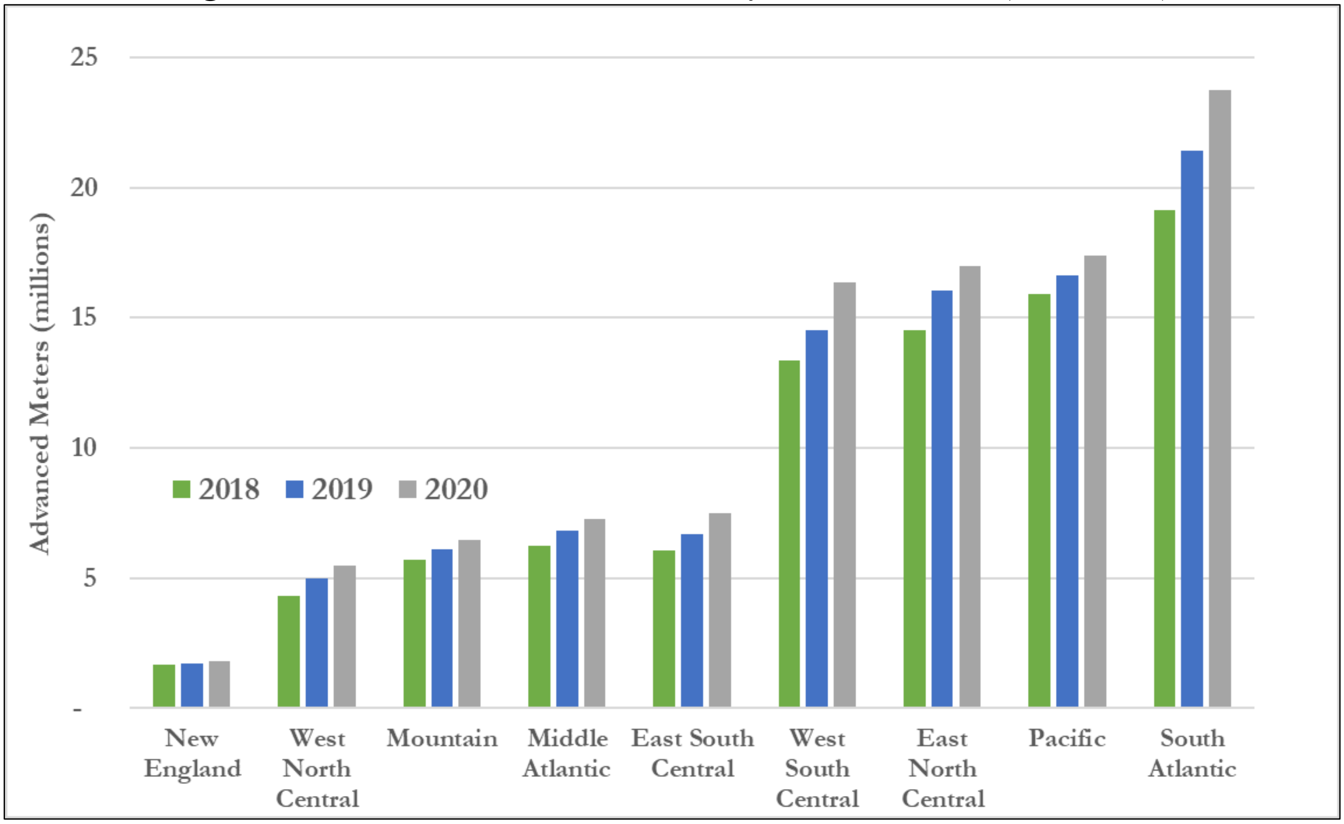
Note: Transportation sector data collected by EIA contain a relatively small number of meters and are not reported separately here. Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently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

Figure 2-2 displays the number of advanced meters by Census Division from 2018 to 2020. Utilities in all nine Census Divisions reported more advanced meters in operation in 2020 compared with 2019. West South Central, East South Central, South Atlantic, and West North Central Census Divisions had the largest percentage increases from 2019 to 2020, with year over year increases of 12.7%, 12.1%, 10.9% and 10.4%, respectively. The West South Central Census Division experienced the largest percentage increase in the number of advanced meters from 2019 to 2020, where utilities reported 1.8 million more advanced meters, representing an increase of 12.7%. Utilities that reported the largest increases in the number of advanced meters in the West South Central Census Division include Entergy Louisiana LLC, Entergy Arkansas LLC, and Entergy Texas Inc., which reported more than 499,000, 334,000, and 295,000 additional advanced meters in 2020.

The South Atlantic Census Division experienced the largest increase in the number of advanced meters, adding approximately 2.3 million from 2019 to 2020. Duke Energy Florida, LLC, Tampa Electric Co., and Virginia Electric & Power Co., respectively, reported more than 687,000, 339,000, and 224,000 additional advanced meters in operation in 2020 as compared to 2019, and represented the largest increases in the South Atlantic Census Division.

Utilities in the East North Central, East South Central, Pacific, West North Central, Middle Atlantic, Mountain, and New England Census Divisions reported 947,000, 809,000, 803,000, 516,000, 451,000, 383,000, and 115,000 more advanced meters in 2020 compared to 2019 respectively.

Figure 2-2: Number of Advanced Meters by Census Division (2018 – 2020)



Development and Issues in Advanced Metering

State Legislative and Regulatory Activities Related to Advanced Metering

Across the country, state regulators and utilities continue to consider how the deployment of advanced meters and associated infrastructure fits in with broader grid modernization efforts. For example, utilities in Massachusetts and Ohio recently filed grid modernization plans that would, among other things, deploy advanced meters to enable customers to achieve energy savings through enrollment in new time-varying rates, and to provide grid operators with more information and visibility into system conditions to support distribution system planning and operations. Proceedings in other states have focused on data security and usage. In New Jersey, state regulators have initiated a proceeding to standardize requirements for utilities in the state to catalog, use, and protect customer usage data collected by advanced meters.

California. On August 4, 2022, the California Public Utilities Commission (California PUC) issued a decision requiring utilities to implement submetering protocols for all customers with plug-in EVs and customer-owned submeters.[4] The California PUC stated that the decision will allow customers to measure

[4] *Decision Adopting Plug-In Electric Vehicle Submetering Protocol and Electric Vehicle Supply Equipment Communication Protocols*, Docket No. R. 18-12-006 (California PUC Aug. 4, 2022) at 2, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K419/496419890.PDF.

their EV charging separately and be billed separately from their primary utility meter without having to install a separate utility meter.[5] The decision also adopts communication protocols for EVSE that will enable widespread vehicle to grid integration. The decision requires that all ratepayer-funded or utility-administered EVSE infrastructure deployed after July 2023 be: (1) capable of operating on Open Charge Point Protocol, which allows for communication between the EVSE and other entities and gives site hosts and operators flexibility and control over chargers; and (2) configured to comply with the International Organization for Standardization 15118, which provides a standardized method for an EV and EVSE to communicate information that enables authentication, automatic billing, and bidirectional charging. Using this protocol allows customers to participate in demand response events, monitor charger status, and respond to local electricity pricing signals.[6]

Connecticut. On October 2, 2019, the Connecticut Public Utilities Regulatory Authority (Connecticut PURA) issued an interim decision in a distribution system planning docket to outline an overarching framework to investigate methods for equitably modernizing the state's electric grid.[7] On October 4, 2019, the Connecticut PURA reopened a proceeding on advanced meters to investigate the business case for statewide advanced meter deployment to support the goals outlined in the Framework for an Equitable Modern Grid.[8] The Connecticut PURA held a number of technical meetings, and requested comments to explore different issues related to AMI deployment since the docket was opened. On March 18, 2022, the Connecticut PURA issued a request for briefs from Connecticut utilities and stakeholders on issues related to AMI deployment, business case proposals, and data access and privacy. On April 29, 2022, the Connecticut PURA received briefs from Eversource, United Illuminating Co., and other interested parties, and subsequently issued another request for briefs by June 2022 to address the following five topics: 1) cost-benefit analysis; 2) the federal Infrastructure Investment and Jobs Act; 3) broadband; 4) AMI deployment strategies; and 5) billing and rate designs.[9] On August 16, 2022, the Connecticut PURA issued a Notice of Technical Meeting for the utilities and stakeholders to discuss comments submitted in the docket, including in particular a proposal by Utilidata to consider a two-step AMI request for proposal, with the first step

[5] *Id.* at 2.

[6] *Id.* at 24-25.

[7] *PURA Investigation into Distribution System Planning of The Electric Distribution Companies*, Interim Decision, Docket No. 17-12-03 (Connecticut PURA, Oct. 2, 2019) at 1, https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0e5fc32986954bf78525875200798b44/$FILE/171203-100219%20InterimDecision.pdf.

[8] *PURA Investigation into Distribution System Planning of the Electric Distribution Companies -Advanced Metering Infrastructure*, Docket No. 17-12-02RE02 (Connecticut PURA, Oct. 4, 2019), https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/f60b8ed80483a0ea8525875200798b49?OpenDocument.

[9] *PURA Investigation into Distribution System Planning of The Electric Distribution Companies Advanced Metering Infrastructure*, Notice of Written Comments, Docket No. 17-12-03RE02 (Connecticut PURA, June 23, 2022), https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0f1f1264ec3497548525886a0048a79e/$FILE/17-12-03RE02%20Notice%20of%20Request%20for%20Written%20Comments.pdf.

focused on procuring distributed intelligence platforms, and the second step focused on procuring the actual meters themselves.[10]

Massachusetts. On May 21, 2021, the Massachusetts Department of Public Utilities (Massachusetts DPU) ordered National Grid, Eversource Energy, and Unitil to file three-year grid modernization plans by July 21, 2021 for the calendar years 2022 to 2025.[11] On July 21, 2021, each utility filed its proposed 2022-2025 Grid Modernization Plans.[12] Eversource plans to deploy approximately 1.4 million advanced meters and associated infrastructure across its service territory by 2028, at a total program cost of $620 million.[13] Eversource will also deploy a meter data management system and a customer information system that will provide granular usage information for its customers and allow them to participate in time-varying rates and other rate design programs.[14] National Grid plans to deploy approximately 1.4 million advanced meters and associated infrastructure starting in 2023 and finish deploying the meters by the third year of deployment, at a total program cost of approximately $487 million.[15] National Grid's plan also includes a Customer Engagement Plan that will educate their customers about AMI.[16] The plan includes development of an online platform that will provide customers access to AMI data, and allow them to learn and participate in various programs to reduce energy costs.[17] Unitil plans to replace its 29,107 existing advanced meters with

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[10] *PURA Investigation into Distribution System Planning of The Electric Distribution Companies - Advanced Metering Infrastructure*, Notice of Technical Meeting, Docket No. 17-12-02RE02 (Connecticut PURA, Aug. 16, 2022), https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/3296bb6d7e102cd9852588a0006f2ea6/$FILE/17-12-03RE02%20Notice%20of%20Technical%20Meeting%209.14.22.pdf.

[11] *Investigation by the Department of Public Utilities on its own Motion into the Modernization of the Electric Grid – Phase Two*, Docket No. D.P.U. 20-69-A (Massachusetts DPU May 21, 2021) at 38, 55, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13552861.

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

[13] *Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Grid Modernization Plan for calendar years 2022 to 2025*, Exhibit ES-AMI-2, Docket No. D.P.U. 21-80 (Massachusetts DPU July 1, 2021) at 3 and Appendix A at 2, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13720285.

[14] *Id.* at 3, 7, 30.

[15] *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval of its Grid Modernization Plan for calendar years 2022 to 2025*, Exhibit NG-AMI-2, Docket No. D.P.U. 21-81 (Massachusetts DPU July 1, 2021) at 26, 45, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13719694.

[16] *Id.* at 46-47.

[17] *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval of its Grid Modernization Plan for calendar years 2022 to 2025*, Exhibit NG-AMI-3, National Grid AMI Implementation Plan, Docket No. 21-81 (Massachusetts DPU July 1, 2021) at 14, 67, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13719694.

newer versions by 2025 at a cost of approximately $11.2 million.[18] The new meters will allow for interval metering that would allow Unitil to implement enhanced rate plans and provide customers the ability to shift energy usage to off-peak hours when rates are lower.[19] Unitil also plans to deploy a Customer Experience Management Solution platform that allows customers to better manage their energy use and accounts, as well as receive personalized rate plans.[20] On September 1, 2021, the Massachusetts DPU bifurcated its investigation of the proposed plans into two separate, parallel tracks.[21] The Massachusetts DPU designated Track 1 to review previously deployed and/or preauthorized grid modernization investments and Track 2 to review the new AMI implementation plans.[22]

New Jersey. On August 23, 2021, the New Jersey Board of Public Utilities (New Jersey BPU) issued a straw proposal to determine the appropriate standardized Data Access Plans for AMI that it will require each New Jersey public utility to adopt.[23] Specifically, the New Jersey BPU sought comment on twelve principles for AMI data handling that collectively are meant to create a data ecosystem for streamlining and accelerating ongoing grid modernization and clean energy efforts. The outlined principles include customer ownership and "hassle-free" handling of data; adoption of standardized customer privacy requirements; data granularity; an easy-to-follow format for data sharing; and the appropriate utility use of AMI data.[24]

On July 29, 2022 the New Jersey BPU announced two upcoming stakeholder meetings to receive feedback on New Jersey BPU staff's Draft Minimum Filing Requirements that each of the state's four distribution utilities will be required to adopt as part of its Data Access Plans for AMI.[25] The requirements aim to lay a foundation for customers to monitor their energy use, compare the benefits of available rate plans, and fully

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[18] *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Grid Modernization Plan for calendar years 2022 to 2025.*, Docket No. D.P.U. 21-82 (Massachusetts DPU July 1, 2021) at 87-88, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/13740253.

[19] *Id.* at 89.

[20] *Id.* at 89-90.

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

[22] *Id.*

[23] *Straw Proposal on Advanced Metering Infrastructure (AMI) Data Transparency, Privacy and Billing*, Docket No. EO20110716 (New Jersey BPU Aug. 23, 2021), https://www.nj.gov/bpu/pdf/publicnotice/EO20110716-%20AMI%20Data%20Access%20Staff%20Straw%20Proposal.pdf.

[24] *Id.* at 8-19.

[25] *In the Matter of Advanced Metering Infrastructure (AMI) Data Transparency, Privacy & Billing*, Docket No. EO20110716 (New Jersey BPU July 29, 2022) at 1, https://nj.gov/bpu/pdf/publicnotice/AMI%20Data%20Access%20Notice%20and%20MFRs.pdf.

participate in the distributed energy resource (DER) aggregations envisioned by FERC Order No. 2222.[26] The requirements also seek to ensure that utilities have the appropriate systems to use AMI data to improve reliability through more efficient distribution system planning, to rapidly isolate and immediately notify operators of an outage, and to assist customers and third parties to propose and site DERs at the most valuable points on the grid.[27]

New Mexico. On October 3, 2022, the Public Service Company of New Mexico (PNM) requested approval from the New Mexico Public Regulation Commission for an implementation plan encompassing the first 6 years of an 11-year grid modernization plan.[28] The 6-year implementation plan proposes to install advanced meters, among other grid modernization efforts, for the 530,000 customers within PNM's service area at a cost of $344 million.[29]

Ohio. On July 15, 2022, the Ohio Edison Company, The Cleveland Electric Illuminating Company, and the Toledo Edison Company jointly submitted an application for approval of the second phase of their grid modernization plan to the Public Utilities Commission of Ohio.[30] These utilities plan to deploy 700,000 advanced meters and related infrastructure in addition to the approximately 700,000 advanced meters that were already approved in the first phase of the grid modernization plan, for a total deployment of approximately 1.4 million advanced meters. The utilities plan to implement the second phase of their grid

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[26] *See Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators*, Order No. 2222, 172 FERC ¶ 61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g*, Order No. 2222-B, 175 FERC ¶ 61,227 (2021) (Order No. 2222).

[27] *In the Matter of Advanced Metering Infrastructure (AMI) Data Transparency, Privacy & Billing*, Docket No. EO20110716 (New Jersey BPU July 29, 2022) at 5, https://nj.gov/bpu/pdf/publicnotice/AMI%20Data%20Access%20Notice%20and%20MFRs.pdf.

[28] *In the Matter of PNM's Application for Authorization to Implement Grid Modernization Components that Include Advanced Metering Infrastructure*, Docket No. 22-00058-UT (New Mexico Public Regulation Commission Oct. 3, 2022) at 3, https://www.pnmforwardtogether.com/assets/uploads/22-00058-UT-2022-10-03-PNM-Grid-Modernization-Application-1-of-2.pdf.

[29] *Id.* at 2-3. *See also In the Matter of PNM's Application for Authorization to Implement Grid Modernization Components that Include Advanced Metering Infrastructure*, PNM Exhibit LES-2, Docket No. 22-00058-UT (New Mexico Public Regulation Commission Oct. 3, 2022) at 4, 22, https://www.pnmforwardtogether.com/assets/uploads/22-00058-UT-2022-10-03-PNM-Grid-Modernization-Application-1-of-2.pdf.

[30] *Application of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Approval of Phase Two of Their Distribution Grid Modernization Plan*, Docket No. 22-0704-EL-UNC (Public Utilities Commission of Ohio July 15, 2022), https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A22G15B52814A02097.

modernization plans, once approved, over a four-year period with an estimated capital investment of $626.4 million.[31]

Virginia. On January 7, 2022, the Virginia State Corporation Commission (Virginia Commission) approved the second phase of a grid modernization plan submitted by Virginia Electric & Power Co. (Dominion).[32] As described in a past report, the Virginia Commission initially denied Dominion's proposal to deploy AMI because the proposal did not include efforts to develop rates that would maximize the potential value of the advanced meters and justify the cost of deployment.[33] The Virginia Commission approved Dominion's more recent proposal to deploy approximately 1.1 million advanced meters by 2024, at a cost of approximately $198 million.[34] The Virginia Commission directed Dominion to explain in a subsequent filing how it is optimizing AMI deployment in coordination with its further development of demand-side management programs and time of use rates.[35] Dominion's deployment plan also includes a customer information platform, which consists of a combination of technologies, applications, and projects to modernize the customer experience, enhance cybersecurity, educate customers, and ultimately prepare customers for the potential development of time-of-use rates.[36]

Collaborative Industry-Government Efforts

The North American Energy Standards Board is an American National Standards Institute accredited industry forum for the development and promotion of standards for wholesale and retail electric and natural gas markets. In May 2022, the North American Energy Standards Board announced a jointly submitted request from the U.S. Department of Energy (DOE), Lawrence Berkley National Lab, and Pacific Northwest National Lab to create standardized, technology-neutral terminology and definitions for DERs

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

[32] *For Approval of a Plan for Electric Distribution Grid Transformation Projects Pursuant to § 56-585.1 A 6 of the Code of Virginia*, Final Order, Docket No. PUR-2021-00127 (Virginia Commission Jan. 7, 2022), https://www.scc.virginia.gov/getattachment/e8e72f65-b3a7-45b3-a395-1f34431715c5/DEV-Grid-Transformation-Final.pdf.

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

[34] *For Approval of a Plan for Electric Distribution Grid Transformation Projects Pursuant to § 56-585.1 A 6 of the Code of Virginia*, Final Order, Docket No. PUR-2021-00127 (Virginia Commission Jan. 7, 2022) at 6, 9, https://www.scc.virginia.gov/getattachment/e8e72f65-b3a7-45b3-a395-1f34431715c5/DEV-Grid-Transformation-Final.pdf.

[35] *Id.* at 10.

[36] *Id* at 11.

that support grid services in the organized markets and on distribution systems.[37] The effort will seek to enable market operators to associate or classify existing market products with common grid services to facilitate more effective communication between market operators and market participants, such as generators, distribution utilities, and DER aggregators. These changes are intended to simplify DER integration and enable the comparison of grid service usage across the markets to improve the accuracy and consistency of information concerning grid service performance.[38]

[37] NAESB, *NAESB to Work with the U.S. Department of Energy, LBNL, And PNNL On Standards Development to Support Market Integration of Distributed Energy Resources*, https://www.naesb.org//pdf4/051922press_release.pdf.

[38] *Id.*

3. Annual Resource Contribution of Demand Resources

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

Retail Demand Response Programs

Table 3-1 reports annual potential peak demand savings for 2019 and 2020 from retail demand response program in each of the nine Census Divisions. The term "potential peak demand savings" refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called."[39] From 2019 to 2020, potential peak demand savings in the United States decreased by approximately 1,549 MW, or 5.0%, from approximately 31,020 MW to approximately 29,470 MW. Despite the nationwide decrease, from 2019 to 2020, utilities in the Middle Atlantic, Mountain, New England, Pacific, and West South Central Census Divisions reported higher potential peak demand savings in 2020.

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

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2019 and 2020)

Census Division	Annual Potential Peak Demand Savings (MW)		Year-on-Year Change	
	2019	2020	MW	%
East North Central	5,362.8	4,909.7	-453.1	-8.4%
East South Central	4,343.1	3,797.0	-546.0	-12.6%
Middle Atlantic	1,463.6	1,504.8	41.3	2.8%
Mountain	1,968.0	2,142.9	174.9	8.9%
New England	179.3	248.5	69.3	38.6%
Pacific	1,803.2	2,346.3	543.1	30.1%
South Atlantic	8,106.8	7,197.1	-909.8	-11.2%
West North Central	5,554.1	4,689.5	-864.5	-15.6%
West South Central	2,238.7	2,634.2	395.5	17.7%
Total	**31,019.5**	**29,470.2**	**-1,549.4**	**-5.0%**

Source: 2020 Form EIA-861 Utility_Data_2020 data file, 2020 Form EIA-861 Demand_Response_2020 data file, 2019 Form EIA-861 Utility_Data_2019 data file, and 2019 Form EIA-861 Demand_Response_2019 data file.

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

Figure 3-1 below shows changes in potential peak demand savings from retail demand response programs in each Census Division from 2018 through 2020. As discussed above, the total decrease in potential peak demand savings from 2019 to 2020 was concentrated in four of the nine Census Divisions. Based on the EIA data, the South Atlantic Census Division and West North Central Census Division experienced the largest drop in potential peak demand savings from 2019 to 2020, representing 910 MW and 865 MW declines, respectively. Evergy Kansas Central reported 118 MW less potential peak demand savings in the West North Central Census Division. The decrease in the East North Central Census Division was primarily attributable to Ohio Power Company, which reported 486 MW less potential peak demand savings, while the decrease in the East South Central Census Division was primarily from East Kentucky Power Coop., Inc., which reported 554 MW less. Despite the overall decreases in potential peak demand savings in these four Census Divisions, some utilities in these Census Divisions reported higher potential peak demand savings in 2020 compared with 2019.

Despite the nationwide decrease from 2019 to 2020, utilities in five Census Divisions reported higher potential peak demand savings in 2020. Utilities in the Pacific Census Division reported 543 MW more in 2020, which represented a 30.1% increase and the highest net absolute increase in MW of potential peak demand savings among Census Divisions. Notably, Portland General Electric in Oregon reported 39 MW higher potential peak demand savings in 2020. Utilities in the New England Census Division reported 69.3 MW more potential peak demand savings in 2020, which represented the largest percent increase among

Census Divisions at 38.6%. This increase is primarily attributable to NSTAR Electric Company and Connecticut Light & Power Company, which reported 83 MW and 60 MW of additional potential peak demand savings, respectively. Additionally, Consolidated Edison Company of New York Inc. and Long Island Power Authority reported 30 MW and 25 MW more potential peak demand savings, respectively, in the Middle Atlantic Census Division. In the Mountain Census Division, Public Service Company of Colorado reported 501 MW in retail potential peak demand savings, an increase of 89 MW from 2019. Finally, in the West South Central Census Division, Entergy Texas Inc. reported 95 MW more potential peak demand savings.

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

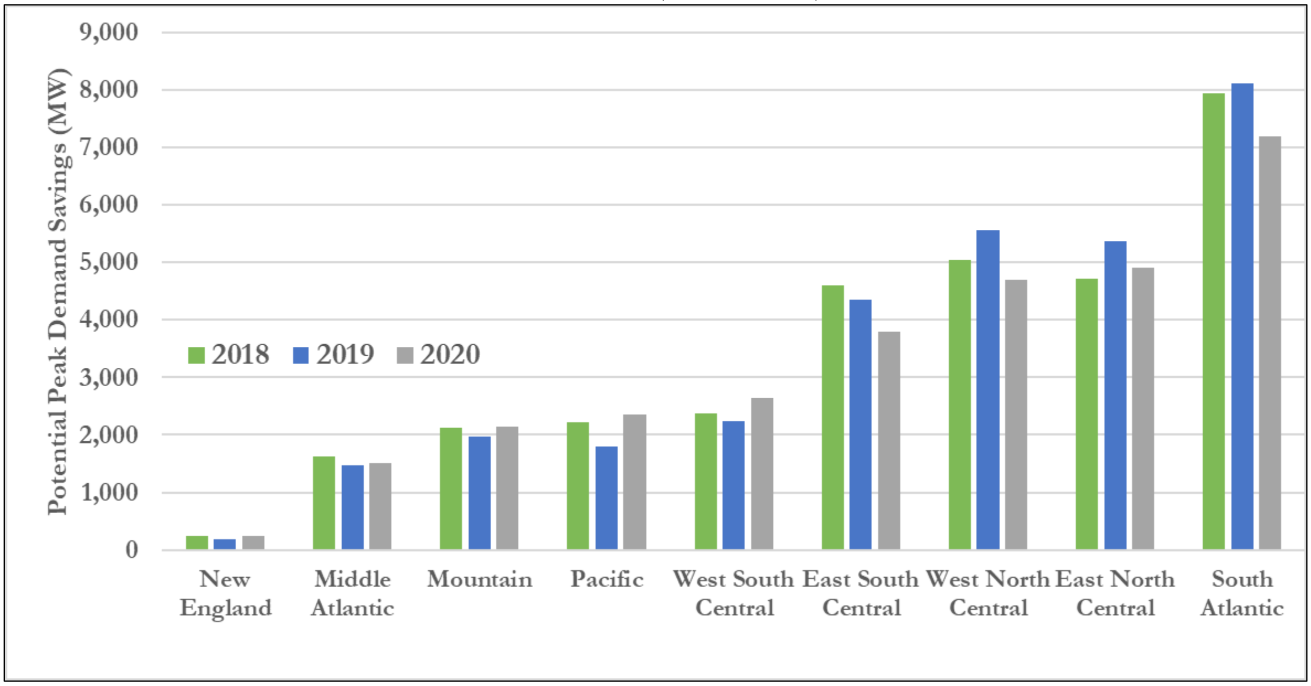

Table 3-2 below shows the relative contribution of retail potential peak demand savings from the residential, commercial, and industrial customer classes in 2020. For the second consecutive year, utilities reported over 15,000 MW of potential peak demand savings from the industrial class, roughly half of all reported total potential peak demand savings. In five of the nine Census Divisions, utilities in aggregate reported the greatest potential peak demand savings from the industrial customer class. The relative contribution of each customer class in 2020 is similar to that which was reported in 2019, with the residential, commercial, and industrial classes accounting for approximately 29%, 20% and 51% of potential peak demand savings, respectively. The South Atlantic Census Division, which comprises the largest number of states and utilities, reported almost one quarter of the total national potential peak demand savings in 2020.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division and Customer Class (2020)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	838.3	693.2	3,378.2	4,909.7
East South Central	345.0	154.4	3,297.6	3,797.0
Middle Atlantic	228.7	506.8	769.4	1,504.8
Mountain	960.5	531.3	651.1	2,142.9
New England	59.5	144.8	44.3	248.5
Pacific	401.2	339.6	1,605.6	2,346.3
South Atlantic	3,287.2	1,729.9	2,180.0	7,197.1
West North Central	1,817.8	1,125.8	1,745.9	4,689.5
West South Central	596.5	611.6	1,426.2	2,634.2
Total	**8,534.7**	**5,837.3**	**15,098.2**	**29,470.2**

Source: 2020 Form EIA-861 Demand_Response_2020 data file and 2020 Form EIA-861 Utility_Data_2020 data file.

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

Wholesale Demand Response Programs

Table 3-3 below estimates participation in the seven RTO/ISO[40] wholesale demand response programs in 2020 and 2021. Demand response participation in the wholesale markets increased by approximately 1,833 MW, or 6.0%, from 2020 to 2021. On a regional basis, demand response totals increased in all but one of the wholesale markets. PJM reported 999 MW more demand response resources in 2021, which represented the largest annual increase among the RTOs and ISOs. Based on the reported data, 6.6% of the wholesale market peak demand for all RTOs/ISOs could be met by demand response resources in 2021, compared with 6.3% in 2020.

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

Table 3-3: Demand Response Resource Participation in RTOs/ISOs (2020 & 2021)

RTO/ISO	2020		2021		Year-on-Year Change	
	Demand Resources (MW)	Percent of Peak Demand[8]	Demand Resources (MW)	Percent of Peak Demand[8]	MW	Percent
CAISO[1]	3,290 .0	7.0%	3,900.0	8.9%	610.0	18.5%
ERCOT[2]	3,774.0	5.1%	4,354.5	5.9%	580.5	15.4%
ISO-NE[3]	423.4	1.7%	533.7	2.3%	110.4	26.1%
MISO[4]	12,877.0	11.0%	12,197.0	10.2%	-680.0	-5.3%
NYISO[5]	1,274.1	4.2%	1,345.5	4.4%	71.4	5.6%
PJM[6]	8,915.0	6.3%	9,914.0	6.8%	999.0	11.2%
SPP[7]	34.2	0.1%	176.2	0.3%	142.0	415.2%
Total	**30,587.7**	**6.3%**	**32,421.0**	**6.6%**	**1,833.3**	**6.0%**

Sources for demand resource data: [1] CAISO, 2020 and 2021 Annual Reports on Market Issues and Performance. Totals for 2020 were confirmed in Commission staff discussions with CAISO Department of Market Monitoring. Totals for 2021 represent nameplate capacity; [2] Estimated based on ERCOT, 2020 and 2021 Annual Reports of Demand Response in the ERCOT Region; [3] ISO-NE, Monthly Statistics Report, presented at the July 2020 and July 2021 Demand Resources Working Group Meetings; [4] Potomac Economics, 2021 State of the Market Reports for the MISO Electricity Markets. For 2021, the MISO market monitor accounted for resources cross-registered in multiple demand response categories in its demand response capability totals and provided updated figures for prior years. As a result, the MISO 2020 value for demand resources was revised in the 2021 Assessment of Demand Response to align with the updated figures; [5] NYISO, 2020 and 2021 Annual Reports on Demand Side Management Programs of the New York Independent System Operator, Inc.; [6] PJM, 2020 and 2021 Demand Response Operations Markets Activity Reports. Totals represent "unique MW"; [7] SPP, 2020 and 2021 State of the Market Reports; [8] Sources for peak demand data include: CAISO 2020 and 2021 Annual Reports on Market Issues and Performance; ERCOT 2020 & 2021 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report (July 2020 and July 2021); 2020 and 2021 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2021 and 2022; 2021 PJM State of the Market Report, Vol. 2; SPP 2020 and 2021 State of the Market Reports.

Notes: Commission staff has not independently verified the accuracy of the sources listed. Values from source data are rounded for publication. The 2020 values for ERCOT and ISO-NE were revised to correct typographical errors in this table in the 2021 Assessment of Demand Response and Advanced Metering. The totals in this year's table are the same as totals reported in discussion of RTO/ISO programs in the body of the 2021 Assessment of Demand Response and Advanced Metering. The 2020 values for demand resources and their contribution to the percent of peak demand were updated to reflect the aforementioned changes.

In 2021, CAISO reported 3,900 MW of demand response capability, a 18.5% increase from the 3,290 MW reported in 2020. This increase was due in part to a reported 20% increase in utility-operated demand response from 2020 to 2021. Utility demand response programs are operated by load-serving entities and mainly consist of reliability demand response resources that are only called on under emergency conditions after CAISO issues a system warning.[41] The total utility demand response resource capability significantly increased in the second half of 2021 compared with 2020. Third-party demand response capability increased in the first half of 2021 compared with 2020. Third-party demand response is operated by non-utility providers under contract to supply capacity for utilities. All third-party demand response resources registered in 2021 were proxy demand response resources, which bid into the CAISO markets as supply.[42]

In ERCOT, demand response resource participation in 2021 increased by approximately 581 MW, or 15.4%, to 4,355 MW. ERCOT reported an increase of 536 MW in demand response resources providing frequency response through the Responsive Reserve Service program. ERCOT also reported an increase of 44 MW in resources providing Emergency Response Service.

ISO-NE reported approximately 534 MW of Active Demand Capacity Resources enrolled in July 2021, the month of the highest peak demand in ISO-NE. This represents a 110 MW, or 26.1%, increase in resource participation in ISO-NE from 423 MW of Active Demand Capacity Resources enrolled in July 2020.

In 2021, the market monitor for MISO started reporting totals for resources that were cross-registered to participate in more than one category of demand response. As such, totals for MISO in some categories are different than the totals that were reported in last year's report. MISO reported a decrease in demand response capability of 680 MW, or 5.3%, from 12,877 MW in 2020 to 12,197 MW in 2021. This decrease was largely due to a decrease of 654 MW in Emergency Demand Response resources from 1,439 MW in 2020 to 785 MW in 2021. In 2021, 158 MW of Emergency Demand Response resources were cross-registered as Load Modifying Resources, while 476 MW of Demand Response Resources were cross-registered as Load Modifying Resources.

In NYISO, demand response participation increased by approximately 71 MW, or 5.6%, from 1,274 MW in 2020 to 1,346 MW in 2021. The annual increase was due to a 101 MW increase in enrollment of resources providing Operating Reserves in NYISO's Demand-Side Ancillary Services Program, from 75 MW in 2020 to 176 MW in 2021. However, NYISO reported a 30 MW decrease in its Special Case Resource program, from 1,198 MW in 2020 to 1,168 MW in 2021.

PJM reported the largest annual change in demand response resource capability. From 2020 to 2021, the total demand response resource capability increased by 999 MW, or 11.2%, from 8,915 MW in 2020 to 9,914 MW in 2021. The significant increase in demand response capability resulted from increases in the load management and economic programs. Enrollment in load management programs increased by 972 MW, from 7,861 MW in 2020 to 8,833 MW in 2021, while enrollment in its economic program increased by

[41] CAISO, *Demand Response Issues and Performance 2021* at 6-7, http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf.

[42] CAISO, *Demand Response Issues and Performance 2021* at 6-7, http://www.caiso.com/Documents/Demand-Response-Issues-Performance-Report-Jan-12-2022.pdf.

744 MW, from 1,361 MW in 2020 to 2,105 MW in 2021.[43] Conversely, PJM reported a 51 MW decrease in enrollment in its Price Responsive Demand program, from 613 MW in 2020 to 562 MW in 2021.[44]

In its 2021 State of the Market Report, SPP reported a total demand response capability of 176 MW from 102 demand response resources. This represents a 142 MW increase from 2020, when SPP reported a total of 34 MW of demand response capability. There were no registered demand response resources in the SPP market between January 2015 and December 2019.[45] Total demand response capability in SPP has increased from 0.3 MW in 2019 to 176 MW in 2021, representing a 585.7% increase in three years.

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 June 2022, in the western portion of PJM, heat and subsequent severe storms and tornadoes affected dozens of bulk electric system facilities, including transmission and generation facilities. PJM issued several load shed directives to AEP to alleviate local thermal overloads to mitigate the potential for cascading transmission facility outages.[46] PJM also issued a Pre-Emergency and Emergency Load Management Reduction Action for the Marion area of AEP, which directed Curtailment Service Providers in the area to dispatch demand response resources in the area with 30, 60 and 120 minute lead times.[47] According to

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[43] Some economic demand response resources are also registered to participate in load management programs. Resources in both programs do not need to register for the same amount of MW. *See* Monitoring Analytics, *2021 PJM State of the Market Report, Vol. 2* at 356, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf

[44] The values reported for Load Management and Economic programs may include resources registered in both programs and the total demand response resource capability reported here represents Unique MW. According to PJM, Unique MW represents "the total estimated demand reduction assuming full Load Management and Economic reductions." *See* PJM, *2021 Demand Response Operations Markets Activity Report*, (March 2022) at 4, https://www.pjm.com/-/media/markets-ops/dsr/2021-demand-response-activity-report.ashx.

[45] SPP, *State of the Market Report 2021* at 49-50, https://www.spp.org/Documents/67104/2021%20Annual%20State%20of%20the%20Market%20Report.pdf

[46] PJM, Markets and Reliability Committee, *June 13 – June 16 Operational Review* (June 29, 2022), https://www.pjm.com/-/media/committees-groups/committees/mrc/2022/20220629/item-06---june-13-to-june-16-operational-review---presentation.ashx.

[47] *See* PJM, Manual 13: Emergency Operations at 29-31, https://www.pjm.com/~/media/documents/manuals/m13.ashx.

PJM, demand response resources provided approximately 100 MW of load reduction to help alleviate the emergency conditions.

In July 2022, in the ERCOT region, record high electric demand and lower than expected output from wind generators led ERCOT to deploy resources enrolled in the Emergency Response Service program. Deployment of these resources decreases the likelihood of system-wide load shedding events by paying qualified loads to conserve and generators to increase output, within either ten or thirty minutes of being called, to prevent or alleviate an actual or anticipated emergency event.[48] ERCOT also issued a public conservation appeal to customers on two separate days, July 10 and July 13, asking them to voluntarily conserve electricity by reducing their load between the hours of 2 PM and 8 PM.[49] ERCOT noted that in response to the first conservation request, Texas customers reduced demand by approximately 500 MW.

In July 2022, customers in SPP also experienced an extreme heat wave that led to several new all-time peak loads in the region. The SPP region spent several days under a Conservative Operations Advisory, which the grid operator declares when it determines that there is a need to operate the system conservatively based on weather, environmental, operational, terrorist, cyber or other events. The Conservative Operations Advisory is the last advisory step that SPP takes before issuing an Emergency Energy Alert to indicate that all available generation has been committed to meet region-wide demand.[50] SPP announced that demand response resources contributed 1.1 MW to the fuel mix during this event.[51]

In August and September 2022, CAISO issued a number of statewide Flex Alerts due to forecasted above-average temperatures that were expected to increase electricity demand, primarily due to air conditioning use.[52] As mentioned in last year's report and discussed further in Chapter 4, the California PUC developed an Emergency Load Reduction Program (ELRP) to procure both supply-side and demand-side resources to make up for anticipated capacity shortfalls in the summers of 2022 and 2023.[53] When a Flex Alert is issued, residential customers participating in the ELRP program to provide demand response can be called upon by

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[48] *See*, ERCOT, *Emergency Response Service*, https://www.ercot.com/services/programs/load/eils.

[49] ERCOT, News Release, *ERCOT Issues Conservation Appeal to Texans and Texas Businesses*, https://www.ercot.com/news/release?id=90030206-5cf5-db8e-13d1-f8fe2bd0128f.

[50] SPP, *Current Grid Conditions*, https://www.spp.org/markets-operations/current-grid-conditions/.

[51] SPP, Press Release, *Southwest Power Pool keeps the lights on as region sets new record for electricity use*, https://www.spp.org/newsroom/press-releases/southwest-power-pool-keeps-the-lights-on-as-region-sets-new-record-for-electricity-use/.

[52] *See* CAISO, Press Release, *California ISO issues Flex Alert for tomorrow, Aug. 17*, http://www.caiso.com/Documents/California-ISO-issues-Flex-Alert-for-tomorrow-Aug-17.pdf; *See also* CAISO, Press Release, *Flex Alert extended to Sunday, Sept. 4 due to high heat*, http://www.caiso.com/Documents/flex-alert-extended-to-sunday-sept-4-due-to-high-heat.pdf.

[53] *See* FERC, *2021 Assessment of Demand Response and Advanced Metering* (Dec. 2021) at 41-42, https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

their distribution utility to reduce their electricity demand during the designated event period.[54] In early September 2022, CAISO issued several Energy Emergency Alerts 2 in an effort to secure more supplies as the historically long heat wave across the state continued.[55] After declaring an Energy Emergency Alert 2, CAISO can call upon energy demand response resources, called Reliability Demand Response Resources, to help maintain reliability and avoid widespread outages.[56]

[54] California PUC, *Emergency Load Reduction Program*, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

[55] CAISO, Press Release, *Energy Emergency Alert 2 declared to protect grid* (Sep. 2022), https://www.caiso.com/Documents/energy-emergency-alert-2-declared-to-protect-grid.pdf.

[56] CAISO, *Reliability Demand Response Resource Participation Overview* at 10 (May 2014), https://www.caiso.com/Documents/ReliabilityDemandResponseResourceParticipationOverview.pdf.

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

Many regions depend on demand response resources to meet planning requirements in addition to providing opportunities for these resources to meet system needs through 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.

As described in previous reports, California experienced a series of rolling blackouts in the summer of 2020 caused by an extreme heat wave, inadequate energy supply, and certain market practices.[57] In July 2021, the Governor of California issued an Emergency Proclamation that, among other things, directed the California PUC to work with load-serving entities to expand and expedite the approval of demand response programs.[58] In December 2021, the California PUC issued a decision directing the state's three investor-owned utilities to collectively procure an additional 2,000 MW to 3,000 MW of demand-side and supply-side contingency resources to maintain reliability during extreme weather events.[59] The California PUC adopted demand-side changes to: (1) expand on the ELRP, which was originally authorized in 2021 to meet identified reliability needs; (2) modify ELRP requirements to increase participation of non-residential customers and increase the compensation rate for participants to $2/kWh; (3) add an ELRP program to allow residential customers to receive compensation for demand reductions during system emergencies; and (4) establish a pilot program to allow aggregators of EVs and/or EV charging stations to participate in ELRP through either managed charging or vehicle-to-grid discharge configurations.

As discussed further in Chapter 5, the California PUC also authorized technology incentives to deploy smart thermostats to facilitate additional customer participation in CAISO managed demand response programs and approved a pilot program to study how price responsive retail rates may help enhance system reliability.

In March 2022, the Northwest Power and Conservation Council published the eighth installment of its regional power plan.[60] The 2021 Northwest Power Plan includes an analysis of the electricity reserve and

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[57] *See* FERC, *2021 Assessment of Demand Response and Advanced Metering* (Dec. 2021) at 25-27, https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

[58] Cal. Emergency Proclamation (July 30, 2021), https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

[59] *Phase 2 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 2022 And 2023*, Docket No. R.20-11-003 (California PUC Dec. 2, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF.

[60] Northwest Power Conservation Council, *The 2021 Northwest Power Plan* (Mar. 2022), https://www.nwcouncil.org/fs/17680/2021powerplan_2022-3.pdf.

reliability requirements for the region and provides a recommended resource strategy to inform the system planning decisions of both public and private load-serving entities in the Northwest. In the 2021 plan, the Northwest Power and Conservation Council recommends that utilities consider implementing time-of-use rates and demand voltage regulation to help meet system needs during anticipated peaking and ramping periods.[61] It estimates that demand response products, including utility-controllable and price-responsive options, could provide approximately 3,721 MW of summer load reduction potential and 2,761 MW of winter load reduction potential.[62] The council also recommended that Bonneville and other Northwest utilities research opportunities to use demand response to support system balancing as more intermittent renewable resources are integrated into the system.[63]

On July 14, 2022, the Public Utility Commission of Texas issued an order to increase the annual budget for Emergency Response Service (ERS) from $50 million to $75 million.[64] ERS is a demand response program administered by ERCOT that involves the procurement and deployment of demand-side resources to prevent or alleviate actual or anticipated emergency events. One day before the order was issued, ERCOT deployed ERS resources, which left a limited supply of remaining ERS funds available to other extreme heat days expected in the near-term forecast.[65] In its order, the Public Utility Commission of Texas stated that the increase in the ERS annual budget strikes the appropriate balance between maintaining reliability and limiting costs to customers.[66]

[61] *Id.* at 47.

[62] *Id.* at 64.

[63] *Id.* at 112.

[64] *Emergency Response Service*, Docket No. 53493 (Public Utility Commission of Texas July 14, 2022), https://interchange.puc.texas.gov/Documents/53493_38_1222175.PDF.

[65] *Id.* at 2.

[66] *Id.* at 9.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter presents regional information on retail demand response[67] and dynamic pricing[68] programs based on EIA data. From 2019 to 2020, utilities in some regions 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 suggests 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. As noted earlier in the report, FERC staff does not independently verify the accuracy of EIA data, but rather reports the data as they were reported by EIA.

Enrollment in Retail Demand Response and Dynamic Pricing

Table 5-1 shows customer enrollment in retail incentive-based demand response programs for each of the nine Census Divisions in 2019 and 2020. From 2019 to 2020, customer enrollment in retail incentive-based demand response programs in the United States increased by over 732,000 customers, or 6.7%. Utilities in six Census Divisions reported aggregate increases in customer enrollment. Utilities in the South Atlantic Census Division reported over 659,000 more customers enrolled in retail demand response programs in 2020, which represented the largest increase among Census Divisions. Utilities in the New England Census Division reported 23,000 more customers enrolled in retail demand response programs in 2020, which represented the largest annual percent increase, 61.7%, among Census Divisions. Utilities in the East North Central, Mountain, Pacific, and West South Central Census Divisions also reported more customers enrolled in retail incentive-based demand response programs in 2020 compared to 2019.

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[67] Demand-side management (DSM) programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. DSM programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. Previously, EIA referred to these programs as "incentive-based" demand response programs. *See* EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3, 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.

[68] Dynamic pricing programs, also known as time-based rate programs, are designed to modify patterns of electricity usage, including the timing and level of electricity demand. They include time-of-use prices, as well as real-time pricing, variable peak pricing, critical peak pricing, and critical peak rebate programs. *See* EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3-4, https://www.eia.gov/survey/form/eia_861s/instructions.pdf.

Table 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2019 and 2020)

Census Division	Enrollment in Retail Demand Response Programs		Year-on-Year Change	
	2019	2020	Customers	%
East North Central	1,284,707	1,341,782	57,075	4.4%
East South Central	205,678	200,229	-5,449	-2.6%
Middle Atlantic	515,734	467,095	-48,639	-9.4%
Mountain	1,182,202	1,233,417	51,215	4.3%
New England	35,554	57,486	21,932	61.7%
Pacific	1,703,932	1,706,329	2,397	0.1%
South Atlantic	3,838,226	4,497,326	659,100	17.2%
West North Central	1,311,735	1,262,248	-49,487	-3.8%
West South Central	855,077	899,751	44,674	5.2%
Total	**10,932,845**	**11,665,663**	**732,818**	**6.7%**

Source: 2020 Form EIA-861 Utility_Data_2020 data file, 2020 Form EIA-861 Demand_Response_2020 data file, 2019 Form EIA-861 Utility_Data_2019 data file, and 2019 Form EIA-861 Demand_Response_2019 data file.

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

Figure 5-1 below shows changes in customer enrollment in retail incentive-based demand response programs in each Census Division from 2018 to 2020. Utilities in the South Atlantic Census Division continued to report the most customers enrolled in retail incentive-based demand response programs in 2020, with over 4.4 million customers enrolled in 2020. Duke Energy Progress in North Carolina and Potomac Electric Power Co. in Maryland reported over 181,000 and 197,000 more customers enrolled in 2020, respectively, which represented the largest increases in the South Atlantic Census Division. In the New England Census Division, Connecticut Light & Power Co. and NSTAR Electric Company reported 10,000 and 9,000 more customers enrolled, respectively. The increase in customer enrollment in the East North Central Census Division was primarily from 59,000 more customer enrollments reported by Duke Energy Indiana, 46,000 more customer enrollments reported by Duke Energy Ohio, and 43,000 more customer enrollments reported by Consumers Energy in Michigan in 2020. In the West South Central Census Division, Austin Energy reported 13,000 more customer enrollments, Arizona Public Service in the Mountain Census Division reported 49,000 more customer enrollments, and San Diego Gas & Electric in the Pacific Census Division reported 128,000 more customer enrollments.

While the number of customers enrolled in retail demand response programs increased nationwide, the Middle Atlantic, East South Central, and West North Central Census Divisions experienced small aggregate annual decreases in customer enrollment in retail incentive-based demand response programs from 2019 to 2020. The decrease in customer enrollment in the Middle Atlantic Census Division was primarily attributable to Consolidated Edison in New York, which reported 23,000 fewer customer enrollments and Metropolitan Edison in Pennsylvania which reported 17,000 fewer customer enrollments. In the West North Central Census Division, Great River Energy in Minnesota reported 5,900 fewer customer enrollments while Evergy Kansas Central, Evergy Kansas South, and Evergy Metro in Kansas reported

2,100, 4,500, and 3,800 fewer customers enrolled in demand response programs, respectively, totaling 10,500 fewer customers enrolled.

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

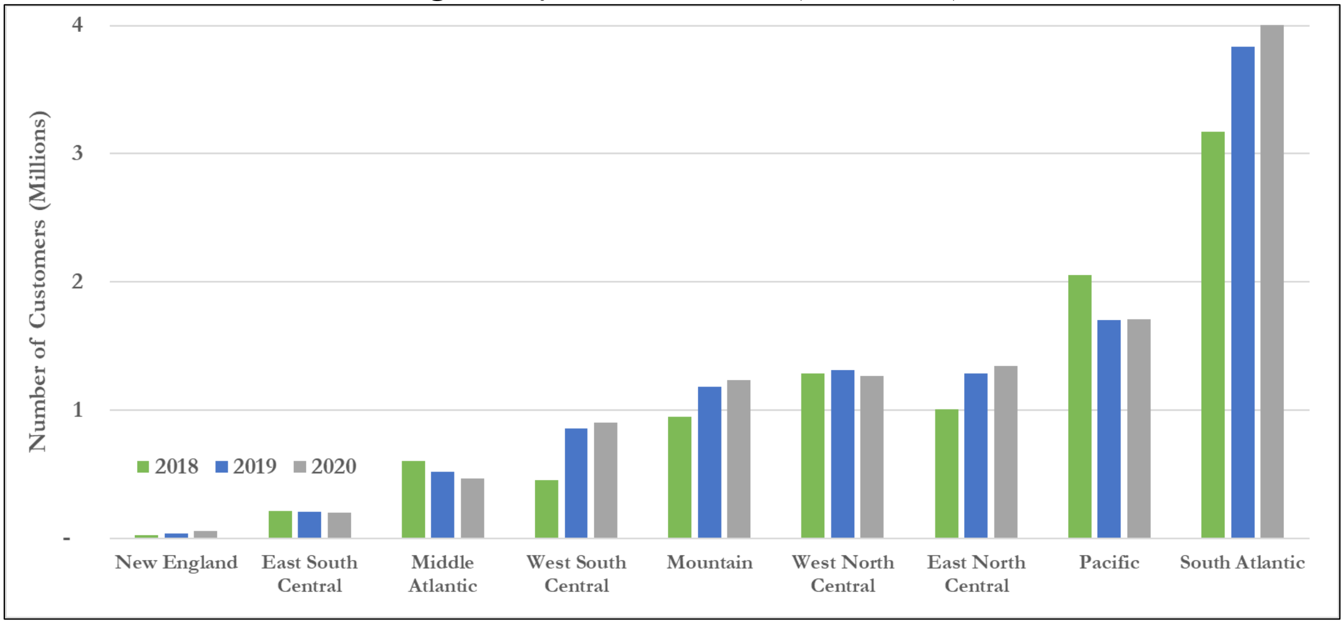

Table 5-2 shows customer enrollment in retail dynamic pricing programs for each of the nine Census Divisions in 2019 and 2020. From 2019 to 2020, customer enrollment in retail dynamic pricing programs in the United States increased by over 1.2 million customers, or 11.3%. Utilities in all Census Divisions reported aggregate increases in customer enrollment. Utilities in the Pacific Census Division experienced the largest aggregate increase in customer enrollment, with over 708,000 additional customers enrolled in retail dynamic pricing programs in 2020 as compared to 2019. 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 March 2019 through October 2020.[69] Utilities in the Middle Atlantic and New England Census Divisions experienced the largest annual percent increases in customer enrollment, 26.9% and 26.2%, respectively.

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[69] *Phase I Decision Addressing Timing of Transition to Residential Default Time-of-Use Rates*, Decision No. D.18-05-011 (California PUC May 10, 2018), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M214/K512/214512974.PDF.

Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2019 and 2020)

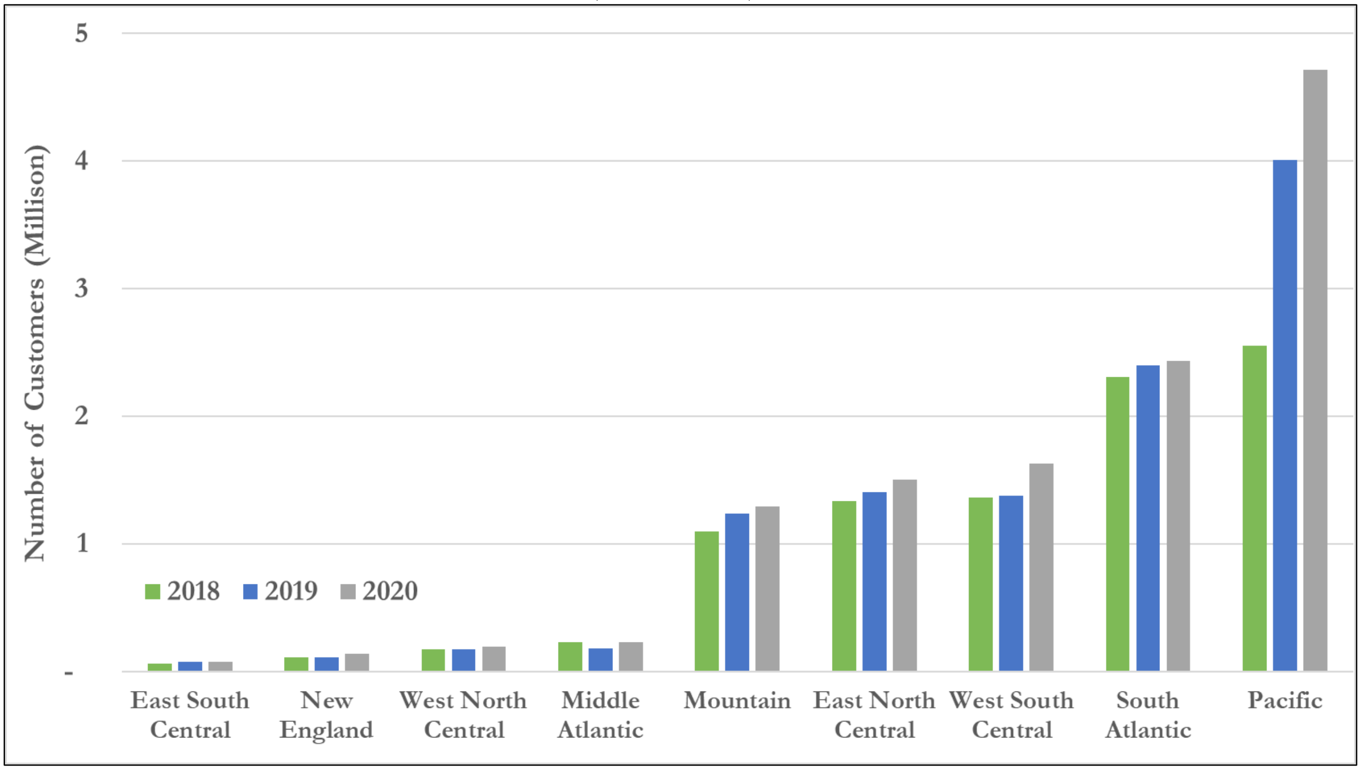
Census Division	Enrollment in Dynamic Pricing Programs		Year-on-Year Change	
	2019	2020	Customers	%
East North Central	1,406,404	1,499,293	92,889	6.6%
East South Central	70,380	75,039	4,659	6.6%
Middle Atlantic	179,692	228,079	48,387	26.9%
Mountain	1,237,492	1,289,443	51,951	4.2%
New England	110,242	139,130	28,888	26.2%
Pacific	4,009,490	4,717,696	708,206	17.7%
South Atlantic	2,400,027	2,429,467	29,440	1.2%
West North Central	172,144	189,341	17,197	10.0%
West South Central	1,372,452	1,627,519	255,067	18.6%
Total	**10,958,323**	**12,195,007**	**1,236,684**	**11.3%**

Source: 2020 Form EIA-861 Dynamic_Pricing_2020 data file, 2020 Form EIA-861 Utility_Data_2020 data file, 2019 Form EIA-861 Dynamic_Pricing_2019 data file, and 2019 Form EIA-861 Utility_Data_2019 data file.

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

Figure 5-2 below graphically displays changes in customer enrollment in retail dynamic pricing programs in each Census Division. In 2020, utilities in the Pacific Census Division continued to report the greatest number of customers enrolled in retail dynamic pricing programs with over 4.7 million customers enrolled. San Diego Gas & Electric reported the largest number of customer enrollments from 2019 to 2020, reporting over 358,000 additional customers, while Pacific Gas and Electric Company reported enrollment of an additional 122,000 customers. While the Pacific Census Division experienced the greatest increase in customer enrolment, other Census Divisions also had significant percentage increases from 2019 to 2020. For example, utilities in the Middle Atlantic and the New England Census Divisions reported over 48,000 and 28,000 more customer enrollments in dynamic pricing programs, respectively, which each represent increases of over 26%. Long Island Power Authority in New York reported over 4,500 additional customers enrolled, which represented the largest increase in customer enrollment in dynamic pricing programs in the Middle Atlantic Census Division. The increase in the New England Census Division may largely result from Constellation Energy Inc. reporting data for the first time in all the New England states except Vermont. In the West South Central Census Division, NextEra Energy in Texas reported over 1,800 more customers enrolled, Southwestern Electric Power Company reported 2,300 more customers enrolled in its Louisiana service territory, and Public Service Company of Oklahoma reported additional customer enrollment of 5,200 customers.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 – 2020)



FERC Demand Response Orders and Activities

CAISO Order No. 2222 Compliance Filing (ER21-2455-000)

On June 17, 2022, the Commission issued an order accepting, subject to a further compliance filing, CAISO's proposed proposal to comply with the requirements of Order No. 2222.[70] The Commission also directed CAISO to make a limited number of changes to its proposals, including revisions regarding the participation of homogenous demand response aggregations in CAISO's markets.[71]

The Commission found that CAISO's proposal to prohibit homogenous demand response resource aggregations from utilizing the Distributed Energy Resource Aggregation (DERA) participation model did not comply with Order No. 2222. The Commission explained that CAISO's Proxy Demand Response (PDR) and Reliability Demand Response Resource (RDRR) participation models did not fully comply with certain requirements outlined in Order No. 2222, including the minimum size threshold requirements and

[70] *Cal. Indep. Sys. Operator Corp.*, 179 FERC ¶ 61,197 (2022).

[71] *Id.* P 50.

the distribution utility review requirements.[72] The Commission directed CAISO to submit a further compliance filing that either: (1) revises the DERA model to allow a homogeneous aggregation of Distributed Curtailment Resources to participate; or (2) demonstrates that the PDR and RDRR participation models are compliant with Order No. 2222.[73]

On August 15, 2022, CAISO submitted a compliance filing with revisions intended to satisfy the Commission directives in the June 2022 compliance order. CAISO proposed to comply with the Commission's directive on demand response by making further revisions to allow aggregations consisting solely of Distributed Curtailment Resources to use the DERA participation model.[74] This proceeding is pending before the Commission.

NYISO Order No. 2222 Compliance Filing (ER21-2460-000, -001)

On June 17, 2022, the Commission also issued an order accepting subject to a further compliance filing, NYISO's proposed revisions to its Open Access Transmission Tariff to comply with the requirements of Order No. 2222.[75] The Commission found that NYISO's Distributed Energy Resource Aggregation participation model appropriately accommodates the physical and operational characteristics of both heterogenous aggregations that include demand response resources and homogeneous aggregations of solely demand response resources.[76] In Order No. 2222, the Commission clarified, among other things, that requirements of Order No. 745 would still apply to demand response resources participating in heterogeneous aggregations.[77] To meet this requirement, NYISO's proposal requires that aggregations independently measure energy injections, withdrawals, and demand reductions, and after the fact, NYISO will evaluate actual demand reductions against the monthly net benefit threshold, and only compensate demand reductions when the real-time Location Based Marginal Price meets or exceeds the monthly net benefit threshold.[78] Accordingly, the Commission found that NYISO's proposal complied with the requirement to apply the requirements of Order No. 745 to demand response resources participating in heterogenous aggregations.

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[72] *Id.* P 49.

[73] *Id.* P 50.

[74] CAISO, Transmittal, Docket No. ER21-2455-002, at 2-3 (filed Aug. 15, 2022).

[75] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,198 (2022).

[76] *Id.* P 89.

[77] Order No. 2222, 172 FERC ¶ 61,247 at P 145.

[78] *N.Y. Indep. Sys. Operator, Inc.*, 179 FERC ¶ 61,198, at P 114 (2022).

MISO Seasonal Resource Adequacy (ER22-495-000, -001, -002)

On August 31, 2022, the Commission issued an order accepting, subject to condition, MISO's changes to its resource adequacy construct to, among other things, implement four seasonal capacity auctions.[79] Prior to the adoption of the seasonal construct, Demand Resources with a notification time of six hours or less that agreed to between five and nine allowable calls were accredited at 80%, while Demand Resources with a notification time of six hours or less and a minimum of 10 allowable calls were accredited at 100%. The changes for Demand Resources align with the shift to seasonal auctions beginning in the 2023/2024 Planning Year: Demand Resources must have a notification time equal to or less than six hours and be capable of being interrupted for at least the first five times in each of the Summer and Winter seasons and at least the first three times for the Fall and Spring seasons.[80] Resources are able to participate in all or none of the seasonal auctions, and obligations apply only to each season. On September 29, 2022, MISO filed tariff revisions in response to several clarification requests[81] regarding MISO's proposed changes.[82]

CAISO Reliability Demand Response Resources (ER22-2700)

On October 24, 2022, the Commission issued an order accepting CAISO's tariff amendments to enhance its dispatch of RDRRs.[83] RDRRs are demand response resources that are dispatched to curtail load when CAISO experiences a transmission or system emergency.[84] CAISO proposed two changes to better reflect RDRRs' operational capabilities in the market. CAISO's first revision involves administratively adjusting the minimum generation output of RDRRs in the market optimization to allow CAISO to dispatch RDRRs through market mechanisms instead of manually dispatching these resources.[85] CAISO's second revision increases the maximum allowable size of RDRRs that can use the discrete dispatch option from 50 MW to 100 MW.[86] CAISO will also allow discrete RDRRs to register up to 100 MW in size or higher if certain

[79] *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[80] MISO Tariff, § 69A.3.5 (41.0.0).

[81] *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141, at PP 85, 89, 250 (2022).

[82] MISO, Compliance Filing, Docket No. ER22-495-002 (filed Sept. 29, 2022).

[83] *Cal. Indep. Sys. Operator Corp.,* 181 FERC ¶ 61,067, at P 1 (2022).

[84] *Id.* P 2.

[85] *Id.* P 5.

[86] *Id.* P 6.

criteria are met.[87] The Commission accepted CAISO's proposal to implement these revisions after November 1, 2022, but no later than December 1, 2022.[88]

NYISO Order Limiting Critical Infrastructure Load from Providing Demand Response Services (ER22-2460-000)

On September 2, 2022, the Commission accepted NYISO's proposed amendments to its Services Tariff that would limit certain critical infrastructure load from providing demand response services.[89] To this end, the amendments define "Critical Electrical System Infrastructure Load" as load that is critical to maintaining the reliable operation of electric system infrastructure, in particular, load that is (i) necessary to maintain the delivery of natural gas, fuel oil, and other fuels used by Generators (including Local Generators) to generate electricity, (ii) likely to impact the supply of natural gas, fuel oil, and other fuel to Generators, or (iii) otherwise likely to impact Generator operation.[90] NYISO also updated its definition of "Demand Reduction" to allow Critical Electrical System Infrastructure Loads to offer demand reduction services only when facilitated by use of a Local Generator.[91]

NYISO stated that these modifications will help maintain reliability by prohibiting curtailment of load that is critical to the operation of generators during NYISO-initiated demand response events.[92] These changes were precipitated by extreme cold weather in February 2021 which caused significant generation and transmission emergencies in Texas.[93] The Commission and the North American Electric Reliability Corporation (NERC) conducted a joint inquiry after that event, and NERC subsequently identified a set of recommended reliability standards intended to support the reliable operation of the bulk power system during cold weather conditions, which NYISO has since adopted for the operation of its demand response program.[94]

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[87] *Id.* P 7.

[88] *Id.* P 13 n. 20.

[89] *N.Y. Indep. Sys. Operator, Inc.*, Docket No. ER22-2460-000 (Sep. 2, 2022) (delegated order).

[90] NYISO, Transmittal, Docket No. ER22-2460-000, at 3 (filed July 22, 2022).

[91] *Id.* at 4.

[92] *Id.*

[93] FERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* at 10-14 (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[94] NERC, *Standard Authorization Request* at 4 (Oct. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/2021-07%20Cold%20Weather%20SAR_clean_SCEC_approved.pdf.

Other Federal Demand Response Activities

Department of Defense

The U.S. Department of Defense (DOD) Defense Logistics Agency (DLA) provides DOD and other federal agencies with a wide range of commodities procurement and energy solutions. The DLA Energy Installation Energy Division serves as a coordinator and facilitator for the DOD's participation in electricity demand response programs.[95] In fiscal year 2021, the DLA facilitated the participation of 36 federal installations in 11 states and the District of Columbia in demand response programs. These installations collectively represent 79 MW of enrolled resources, and as of the date of its report, DLA stated that the programs resulted in approximately $1.35 million in savings in fiscal year 2021.[96]

Department of Energy

In October 2021, DOE announced a $61 million grant award for pilot projects in 10 different "Connected Communities" that will deploy new technologies in more than 7,000 buildings to improve efficiency and to facilitate communications and data exchange with grid operators to optimize the building's electricity consumption. The grid-interactive efficient buildings developed through these grants will use a combination of smart controls, sensors and analytics to communicate with the grid and reduce electricity consumption during periods of peak demand.[97] For example, the Spokane, Washington Connected Communities project seeks to demonstrate a novel model to meet regional and local grid needs through a mix of grid-interactive efficient buildings, energy efficiency programs and DERs. The developers of the project aim to deliver between 1 to 2.25 MW of energy demand flexibility by using flexible building loads augmented with DERs.[98]

In December 2021, DOE announced that 21 state public utility commissions would receive technical assistance from the National Laboratories through DOE's Grid Modernization Initiative to help state regulators develop innovative solutions to improve grid reliability and resilience, enable the adoption of new

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[95] Department of Defense, *Defense Logistics Agency Energy, Fiscal Year 2021 Fact Book* at 17 (Mar. 2022), https://www.dla.mil/Portals/104/Documents/Energy/Publications/DLAEnergyFactBook2021_2.pdf?ver=NJ0NwnrAlbjZSxxhrPjnHA%3d%3d.

[96] *Id.* at 58.

[97] DOE, Office of Electricity, *DOE Invests $61 Million for Smart Buildings that Accelerate Renewable Energy Adoption and Grid Resilience* (Oct. 2021), https://www.energy.gov/articles/doe-invests-61-million-smart-buildings-accelerate-renewable-energy-adoption-and-grid.

[98] Edo Energy, *Edo Awarded DOE Connected Communities Program Funding* (Oct. 2021), https://edoenergy.com/resources/press-release-edo-awarded-doe-connected-communities-program-funding/.

technologies, and achieve state and local decarbonization goals.[99] Ten of the public utility commissions competitively selected to receive technical assistance requested support with DER adoption & integration, which includes consideration of rate designs and demand response program design.[100]

Inflation Reduction Act

On August 16, 2022, President Biden signed into law a budget reconciliation measure, commonly known as the "Inflation Reduction Act of 2022" (IRA).[101] The IRA includes funding and financial incentive provisions focused on promoting the deployment of low- and no-greenhouse gas emissions technologies such as EVs and associated charging equipment, battery energy storage systems, and heat pumps.[102] The IRA includes an extension and expansion of the Energy Investment Tax Credit to include, among other things, energy storage and microgrid controllers.[103] The IRA also provides tax credits for the purchase of new or used EVs;[104] provides funding for the U.S Postal Service to purchase zero-emission vehicles[105] and for the General Service Administration to convert federal facilities into high-performance green buildings;[106] and provides funding to carry our activities under the Defense Production Act to accelerate domestic production of clean energy technologies, including batteries, solar panel components, and heat pumps.[107] The funding and financial incentives included in the IRA will likely accelerate the pace of deployment for customer-sited DERs and associated technologies that could allow these new DERs to provide demand response services in wholesale and retail markets.

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[99] DOE, Office of Energy Efficiency and Renewable Energy, *DOE Announces Technical Assistance for State Utility Regulators to Address Challenges Related to a Transforming Electric Grid* (Dec. 2021), https://www.energy.gov/eere/articles/doe-announces-technical-assistance-state-utility-regulators-address-challenges.

[100] Lawrence Berkley National Lab, *Technical Assistance to State Public Utility Commissions*, https://emp.lbl.gov/projects/technical-assistance-state-public-utility/.

[101] Congressional Research Service, *Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change* at 1 (Oct. 2022), https://crsreports.congress.gov/product/pdf/R/R47262.

[102] *Id.* at 2-3.

[103] *Id.* at 4.

[104] *Id.* at 11.

[105] *Id.* at 13.

[106] *Id.* at 17.

[107] *Id.* at 19.

Developments and Issues in Demand Response

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

Many recent state proceedings have focused on how to effectively integrate customer sited DERs, with a particular focus on EVs, especially given concerns among grid operators that uncoordinated EV charging could threaten to overload components of the distribution system or require costly upgrades. Several states, including Arizona, Illinois, and New Mexico, are considering new time-varying rate designs as part of larger transportation electrification plans. Other states, such as California, are further investigating how supply-side programs and increased demand flexibility can help ensure the reliability of the overall system.

Arizona. On December 15, 2021, the Arizona Corporation Commission approved a comprehensive, statewide transportation electrification plan from Tucson Electric Power Company (TEP) and Arizona Public Service Company (APS).[108] The transportation electrification plan aims to encourage further adoption of EVs by implementing time-of-use rates to provide incentives for EV owners to charge during off-peak hours.[109] Specifically, TEP explains that some of their existing residential rates, including their Super Off-Peak Time-of-Use rates, encourage EV charging between 10 p.m. and 5 a.m. during the Summer and Winter periods to limit grid impacts from EV charging. TEP and APS also plan to accommodate the statewide EV-adoption goal by building EV infrastructure, engaging in customer outreach, and providing standalone rates for EV owners.[110]

California. As mentioned in Chapter 4, the California PUC directed the state's three investor-owned utilities in December 2021 to modify, expand and establish demand-side programs to increase participation of demand response resources in the short-term to mitigate the risk of capacity shortfalls during anticipated extreme weather events in the summers of 2022 and 2023.[111] In addition to directing the changes to the ELRP program described above, the California PUC authorized up to $22.5 million in technology incentives to subsidize the deployment of up to 300,000 smart thermostats ($75 per thermostat) in hot climate zones from 2022-2023. To ensure the smart thermostats actually control air conditioning load during times of emergencies, retail customers that receive a thermostat rebate will be required to pre-enroll in a CAISO

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[108] *In the Matter of Electric Vehicles, EV Infrastructure, and the Electrification of the Transportation Sector in Arizona*, Docket No. E-00000A-21-0104 (Arizona Corporation Commission Dec. 15, 2021), https://docket.images.azcc.gov/0000205573.pdf?i=1661885889420.

[109] *Comprehensive Transportation Electrification Plan for Arizona, Phase Two*, Docket No. RU-00000A-18-0284 (Arizona Corporation Commission Apr. 1, 2021) at 67, https://docket.images.azcc.gov/E000012626.pdf?i=1661887326765.

[110] *Id.* at 69-70.

[111] *Phase 2 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 2022 And 2023*, Docket No. R.20-11-003 (California PUC Dec. 21, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M428/K821/428821475.PDF.

market integrated supply-side demand response program.[112] The California PUC also approved a Southern California Edison dynamic rate pilot program to study how price responsive programs may enhance system reliability. The pilot will be open to Southern California Edison's residential, commercial, and industrial customers, and the utility may prioritize customers with smart enabled price-responsive end-uses such as EV charging, behind-the-meter batteries, and other controllable loads.[113]

On July 14, 2022 the California PUC issued an order instituting a rulemaking to enable widespread demand flexibility through electric rates.[114] The California PUC will seek to establish policies and modify rates to achieve the following goals: (1) enhance the reliability of California's electric system; (2) make electric bills more affordable and equitable; (3) reduce curtailment of renewable energy and greenhouse gas emission; (4) enable widespread electrification of buildings and transportation; (5) reduce long-term system costs through more efficient pricing of electricity; and (6) enable participation in demand flexibility by both bundled and unbundled customers.[115]

On October 12, 2022, the California Energy Commission adopted amendments to the state's load management standards to give consumers more timely and accurate information on electricity costs and to provide them with opportunities to shift demand to periods when lower cost electricity is available.[116] The updated standards require California utilities and community choice aggregators to: (1) develop and offer to customers at least one retail rate that changes at least hourly; (2) provide and update hourly and time-varying rates in the California Energy Commission's database; (3) develop a standard tool for third party services to access rate information for customers; and (4) integrate information about time-dependent rates and automation technologies into customer education and outreach programs.[117]

Connecticut. On October 4, 2021, the Connecticut PURA initiated an investigation to explore strategies to optimize the integration of medium and heavy-duty EV charging.[118] This investigation aims to establish a

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[112] *Id.* at 75.

[113] *Id.* at 98-99.

[114] *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, Docket No. R 22-07-0005 (California PUC July 14, 2022), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K285/496285639.PDF.

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

[116] California Energy Commission, *CEC Adopts Standards to Help Consumers Save Energy at Peak Times* (Oct. 2022), https://www.energy.ca.gov/news/2022-10/cec-adopts-standards-help-consumers-save-energy-peak-times.

[117] California Energy Commission, *2022 Load Management Standards Rulemaking Fact Sheet* at 1 (Oct. 2022), https://www.energy.ca.gov/sites/default/files/2022-10/Load_Management_Fact_Sheet_ADA.pdf.

[118] *PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging*, Docket No. 21-09-17 (Connecticut PURA Oct. 4, 2021), https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/1e5d07068502929f8525876400512067/$FILE/21-09-17%20Notice%20of%20Proceeding.pdf.

statewide EV charging program to foster a self-sustaining EV market in Connecticut to meet the state's greenhouse gas reduction and zero-emission vehicle targets.[119] To help achieve the state's goal of increasing the sales of zero-emission vehicles, the Connecticut PURA is undertaking a process to establish rate structure(s) and reporting metrics that facilitate the integration of existing, evolving, and emerging medium and heavy-duty zero-emission vehicle-related technologies that encourage efficient grid utilization and flexibility, and balance ratepayer costs.[120] In response to a multi-state action plan providing policy recommendations to integrate medium- and heavy-duty zero-emission vehicles and other public comments, several rate designs are being considered by the Connecticut PURA in discussion with stakeholders, such as fully volumetric rates and time-of-use charges.[121]

Illinois. On June 30, 2022, Ameren Illinois Company (Ameren Illinois) filed a petition for approval of its proposed Beneficial Electrification Plan with the Illinois Commerce Commission (Illinois Commission).[122] Ameren's previously approved Electric Vehicle Charging Program encourages EV charging at off-peak times by providing bill credits and preferred period delivery credits.[123] Under the proposed plan, Ameren plans to modify its program to expand eligibility to a larger group of customers, including multifamily facilities, education facilities, transit facilities, private fleet facilities, and local government facilities.[124] On July 1, 2022, the Commonwealth Edison Company (ComEd) also filed a petition for approval of its

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[119] *PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging*, Docket No. 21-09-17 (Connecticut PURA June 7, 2022) at 2, https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/2ed65674d917a5de8525885a00630502/$FILE/21-09-17%20MHD%20Tech%20Meeting%202%20Stakeholder%20Discussion.pptx.

[120] *Id.* at 2.

[121] *PURA Investigation into Medium and Heavy-Duty Electric Vehicle Charging*, Docket No. 21-09-17 (Connecticut PURA June 7, 2022) at 4, https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/2ed65674d917a5de8525885a00630502/$FILE/21-09-17%20MHD%20Tech%20Meeting%202%20Stakeholder%20Discussion.pptx. *See also* NESCAUM, *Multi-State Medium- and Heavy-Duty Zero-Emission Vehicle Action Plan* at 34 (Mar. 10, 2022), https://www.nescaum.org/documents/mhd-zev-action-plan-public-draft-03-10-2022.pdf.

[122] *Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act*, Docket No. 22-0431 (Illinois Commission June 30, 2022), https://www.icc.illinois.gov/docket/P2022-0431/documents/325722.

[123] *Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act*, Ameren Exhibit 2.1, Docket No. 22-0431 (Illinois Commission June 30, 2022) at 3, https://www.icc.illinois.gov/docket/P2022-0431/documents/325722.

[124] *Id.* at 6-9.

proposed Beneficial Electrification Plans with the Illinois Commission.[125] ComEd proposes several different residential programs to offset the upfront cost of EVs through rebates. In order to receive rebates, ComEd proposes to require customers to enroll in its Basic Electric Service Hourly pricing program for at least three years, which charges time-varying rates to encourage customers to charge their EVs during off-peak hours.[126]

Maine. In April 2021, stakeholders submitted a report as part of the Maine Climate Council initiative[127] to develop a four-year climate plan to decrease greenhouse gas emissions by 45% by 2030 and 80% by 2050.[128] The report included recommendations to explore dynamic rate design that would encourage customers to shift their electricity use to off-peak hours.[129] In April 2022, the Maine Public Utilities Commission issued a straw proposal aimed at helping to advance the goals set forth in that report.[130] The straw proposal describes certain rate designs and approaches that could apply to EV charging, heat pumps, and energy storage facilities with input from three utilities in the state.[131] The proposal recommends volumetric rates for residential and small commercial customers that would be based upon existing optional residential and small commercial time-of-use rates with modifications, such as increasing the customer charge and lowering the usage charges. These rates are proposed to be available as "whole house" rates or separately metered by the EV charging load.[132]

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[125] Pet*ition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX*, Docket No. 22-0432 (Illinois Commission July 1, 2022), https://www.icc.illinois.gov/docket/P2022-0432/documents/325766.

[126] Pet*ition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX*, ComEd Ex. 1.01, Docket No. 22-0432 (Illinois Commission July 1, 2022) at 31, https://www.icc.illinois.gov/docket/P2022-0432/documents/325766.

[127] An Act to Promote Clean Energy Jobs and To Establish the Maine Climate Council, S.P. 550 - L.D 1679, 129th Leg., (Me. 2019), https://legislature.maine.gov/bills/getPDF.asp?paper=SP0550&item=3&snum=129.

[128] Maine Utility/Regulatory Reform and Decarbonization Initiative, *Stakeholder recommendations to plan, build, and operate the electric grid that is needed to meet Maine's climate and energy requirements* (Apr. 2021), https://www.betterenergy.org/wp-content/uploads/2021/04/MURRDI-Stakeholder-Process-Summary.pdf.

[129] *Id.* at 19-21.

[130] *Rate Design to Promote State Policies*, Docket Nos. 2021-00325, -00198 (Maine Public Utilities Commission Apr. 7, 2022), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={577480D9-9D8E-4FEC-920F-382350898FCC}&DocExt=pdf&DocName={577480D9-9D8E-4FEC-920F-382350898FCC}.pdf.

[131] *Id.*

[132] *Id.* at 3.

Maryland. On January 11, 2022, the Maryland Public Service Commission (Maryland PSC) issued an order approving, in part, modifications proposed by five utilities to their existing EV charging program offerings for residential customers, multifamily facilities, fleet operators and workplace charging stations.[133] In a previous filing, Baltimore Gas and Electric Company had requested a waiver from certain provisions in the Maryland Code of Regulations regarding testing, installation, accuracy, and records requirements in order to allow residential smart chargers installed pursuant to residential rebate programs to be used as submeters, in lieu of a dedicated billing meter for EV charging.[134] The Maryland PSC approved the request, stating that the waiver would allow utilities to implement time-variant rates, pursue load management opportunities, and collect important data regarding customer charging habits, without the need for a separate meter. The Maryland PSC also indicated that it would direct staff to work with the state's utilities to develop and propose EV metering regulations before December 31, 2023.[135]

New Hampshire. On April 7, 2022, the New Hampshire Public Utilities Commission approved modifications to EV charging time-of-use rates for residential and commercial customers served by the state's three investor-owned utilities (Unitil, Liberty, and Eversource).[136] The order directs Unitil and Liberty to establish residential and commercial rates for customers with separately metered EVs that have three time of use periods: peak, mid-peak, and off-peak times. The order also directs Unitil and Liberty to develop a peak period of no longer than five hours, and it directs both utilities to ensure that the price ratio between peak rates and off-peak rates, on a $/kWh basis, is no less than 3:1 on average annually.[137] The order directs Eversource to adopt a two-period time-varying rate for residential customers based off evidence that implementation costs would be considerably lower than other more complex alternatives.[138]

New Mexico. On November 1, 2021, the New Mexico Public Regulation Commission approved a Transportation Electrification Program submitted by PNM.[139] The program is designed to encourage

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[133] *In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio*, Docket No. 9478 (Maryland PSC Jan. 11, 2022) at 1, http://webapp.psc.state.md.us/newIntranet/Casenum/CaseAction_new.cfm?CaseNumber=9478.

[134] *Id.* at 75-76.

[135] *Id.* at 77.

[136] *Electric Distribution Utilities Electric Vehicle Time of Use Rates*, Order approving Electric Vehicle Time of Use Rates, Order No. 26,604 (New Hampshire Public Utilities Commission Apr. 7, 2022) at 1, https://www.puc.nh.gov/Regulatory/Orders/2022orders/Documents/26-604.pdf.

[137] *Id.* at 19-21.

[138] *Id.* at 26.

[139] *In the Matter of Public Service Company Of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program*, Docket No. 20-00237-UT (New Mexico Public Regulation Commission Nov. 10, 2021), https://edocket.nmprc.state.nm.us/AspSoft/Dispatcher.aspx?nextPID=inquireCaseSummary&case_mod_id=416973.

customers in PNM's territory to adopt EVs by providing incentives for charging infrastructure and offering EV-specific electricity rates.[140] PNM proposed a new residential pilot rate and a new non-residential pilot rates that will be required for customers receiving rebates under the plan to install charging equipment. The residential pilot rate, called a "Whole-Home EV rate," will be applied to a customer's full load to avoid the estimated cost associated with separately sub-metering the EV. This rate is a time-varying rate that features a low electricity rate, approximately $0.03/kWh, for a customer's whole home between 10:00 p.m. and 5:00 a.m.[141] PNM's non-residential pilot rate is a volumetric, time-varying rate for commercial EV charging stations that would not include demand charges. The rate includes pricing ratios of on-peak to off-peak charges of approximately 2:1 in the non-summer months and approximately 3:1 in the summer months, which are intended to incentivize customers to avoid charging during the peak periods.[142]

North Carolina. On June 24, 2022, the North Carolina Utilities Commission (North Carolina Commission) issued an order approving Duke Energy Carolinas' and Duke Energy Progress' (collectively, "Duke Energy North Carolina") proposed Electric Vehicle Managed Charging Pilot Programs.[143] Duke Energy North Carolina submitted a request earlier in the year for approval of their proposed dynamic pricing rates for EV managed charging pilots.[144] In exchange for a flat charging rate per month for EVs, Duke Energy North Carolina proposed to actively manage participating customers' enrolled vehicles and to retain the ability to schedule up to three managed charging events per month.[145] Duke Energy North Carolina contended that managed charging via this pilot would allow the utility to ensure that charging would occur during low cost, environmentally friendly periods and shape the EV charging patterns to reduce load at peak hours.[146] The North Carolina Commission stated that the flat-rate subscription approach is likely to yield valuable information about charging habits of EV owners, and that Duke Energy

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[140] *In the Matter of Public Service Company Of New Mexico's Application for Approval of its 2022-2023 Transportation Electrification Program*, Exhibit AJB-2, Docket No. 20-00237-UT (New Mexico Public Regulation Commission Dec. 18, 2020) at 1, https://edocket.nmprc.state.nm.us/AspSoft/Dispatcher.aspx?nextPID=inquireCaseSummary&case_mod_id=416973#.

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

[142] *Id.* at 28-29.

[143] *In the Matter of Application by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Electric Vehicle Managed Charging Pilots*, Docket Nos. E-7, Sub 1266 and E-2, Sub 1291 (North Carolina Commission June 24, 2022) at 1, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=9d233192-29a6-479c-9c5f-8b28f78191c3.

[144] *In the Matter of Application by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Proposed Transportation Project*, Docket No. E-2, Sub 1291 (North Carolina Commission Feb. 11, 2022) at 1-2, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=186931ea-9704-4fae-a19d-91cefdefa307.

[145] *Id.* at 2.

[146] *Id.* at 7.

North Carolina has indicated that it intends to explore other EV rate designs based on the results of pilot programs.[147]

On May 19, 2022, Duke Energy North Carolina and several of North Carolina's largest rooftop solar installers filed a settlement agreement with the North Carolina Commission to allow for customers enrolled in net energy metering rates to remain on similarly structured rates rather than transitioning to a default time-of-use rate.[148] The agreement stipulates that current net energy metering customers may remain on their current rate until January 2027, at which point they can decide to transition to a newly proposed "bridge" rate or move to the applicable net energy metering time-of-use rate that will be applicable at that time. This settlement proposal would allow rooftop solar customers to continue participating in net metering in the short-term, with an option to extend net metering, through use of the bridge rate, for up to 15 calendar years after the date on which they submitted an interconnection application.[149] The agreement states that the bridge rate will be terminated if the North Carolina Commission approves a package of rooftop solar incentives that are equal to at least $0.60/watt for time-of-use rates.[150]

Collaborative Industry-Government Efforts

In April 2022, DOE, along with partners from DOE's National Laboratories, state and local governments, utilities, and private entities signed a Memorandum of Understanding (MOU) to collaborate on a Vehicle-to-Everything (V2X) effort to accelerate the deployment and commercialization of technologies to integrate EVs and demonstrate the viability of providing services, like demand response, through bidirectional charging in different circumstances.[151] V2X encompasses different approaches for EVs to inject power back onto the system and, according to the MOU, it includes vehicle-to-grid, vehicle-to-building, and vehicle-to-load technologies and applications. The parties to the agreement plan to develop a roadmap that will help identify scenarios, specific activities, and barriers to V2X functionality. More specifically, they plan to (1) establish and operate test locations for technologies to demonstrate them in real-world settings; (2) establish

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[147] *In the Matter of Application by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for Approval of Electric Vehicle Managed Charging Pilots*, Docket Nos. E-7, Sub 1266 and E-2, Sub 1291 (North Carolina Commission June 24, 2022) at 10, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=9d233192-29a6-479c-9c5f-8b28f78191c3.

[148] *Investigation of Proposed Net Metering Policy Changes*, Docket No. E-100, Sub 100 (North Carolina Commission May 19, 2022) at 1-3, https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=6076eea8-cac2-4c8a-a9f6-a9040ef4fc2b.

[149] *Id* at 3.

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

[151] DOE, *Memorandum of Understanding to Establish the Vehicle-To-Everything Collaboration* (Apr. 21, 2022), https://www.energy.gov/sites/default/files/2022-04/OTT%20V2X%20MOU%20Final.pdf.

realistic use cases for each technology for data collection and evaluation; and (3) analyze data from bidirectional charging demonstrations performance, duty cycles, and monetization of attributes.[152]

As part of the collaboration, the National Laboratories will provide data analytics resources and vehicle and grid technical resources, and DOE will supply other technical assistance and prepare publicly available reports regarding the commercial viability of V2X technologies and any barriers to widespread adoption. The other parties to the MOU will provide access to certain technologies, host sites for generating technical and economic data, share data with other parties for validation, and provide expertise for the development of training to certify contractors for the installation of EVs and EV supply equipment to support V2X deployment.[153]

[152] *Id.* at 3.

[153] *Id.* at 4. The initial parties to the MOU include National Electrical Contractors Association – Los Angeles, International Brotherhood of Electrical Workers – Chapter 11, Fermata Energy, The Waste Management Company-Lancaster, Los Angeles Department of Water and Power, Rhombus, BYD Motors, Inc., The City of Lancaster and City of Lancaster Community Choice Aggregator, Southern California Edison, Zeem Solutions, the California Energy Commission, Pacific Gas and Electric Company, General Motors LLC, Ford Motor Company, San Diego Gas & Electric, Sacramento Municipal Utility District, Lucid Group, Inc., and DOE.

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

The continued deployment of advanced metering infrastructure, and customer-sited energy assets like EVs and battery storage, have increased the opportunities to utilize demand response programs to provide grid services. Demand response programs, peak reduction programs, and critical peak pricing programs can leverage these new technologies to provide flexibility and improve overall system resilience, but certain regulatory barriers limit customer participation in these programs. Outstanding barriers to customer participation, and efforts to address those barriers, are discussed below.

Implementing Time-Based Rates

In order to implement time-varying rates and demand response programs, utilities must first deploy advanced metering infrastructure. While limited advanced meter penetration has historically been a barrier to customer participation in demand response programs, the data in Chapter 2 show that well over 60% of customers now have an advanced meter installed. In a recent report, researchers at Lawrence Berkeley National Laboratory explain that advanced meters and customer-sited energy assets may be under-utilized due to limited customer participation in more complex, dynamic rate offerings. They note that utilities face a challenge when it comes to program design because basic time-of-use rates are simple to administer but poorly aligned with maximizing grid value, and more complicated rates such as critical peak pricing or real-time pricing are well aligned with grid value, but are difficult to administer, which can dissuade customers participation.[154] The researchers also state that very few utility programs provide a premium payment for a more rapid response from demand-side resources.[155]

Lack of Information Sharing and Data Utilization

Customer participation in demand response programs, peak reduction programs, and critical peak pricing programs depends on several factors, including widespread deployment of AMI, investment and development of device communication and data sharing infrastructure to utilize AMI-produced data, and effective rate design to incentivize customers to reduce demand based on signals from a system operator. In September 2022, Mission:Data, a national coalition of energy technology companies that advocates for customer access to energy data, released a report that noted only about 2.9% of the advanced meters deployed with funding issued through DOE's Smart Grid Investment Grant Program (SGIG) have real-

[154] Sydney P. Forrester & Peter Cappers, *Opportunities and Challenges to Capturing Distributed Battery Value via Retail Utility Rates and Programs* (2021), https://emp.lbl.gov/publications/opportunities-and-challenges.

[155] *Id.* at 16.

time data access features enabled.[156] The report also estimates that only 14.7% of customers are offered a Green Button Connect compliant application programming interface to evaluate and manage their energy usage. Green Button Connect is an industry-developed technical standard for exchanging energy usage, account and billing information.[157]

Mission:Data argues many of the electric utilities that received funding through the SGIG program to deploy AMI have underutilized AMI capabilities and have discontinued data access efforts once grant-funded projects were over.[158] Mission:Data notes that the Infrastructure Investment and Jobs Act, signed into law in November 2021, allocated an additional $3 billion to the SGIG program.[159]

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[156] Mission:Data, *Deactivated: How Electric Utilities Turned off the Data-Sharing Features of 14 Million Smart Meters* at 3, https://static1.squarespace.com/static/52d5c817e4b062861277ea97/t/631253069bdd82629d3ea079/1662145291709/Deactivated_white_paper.pdf.

[157] *Id.* at 3-4.

[158] *Id.* at 8.

[159] *Id.* at 9.

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Demand Response and Advanced Metering

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