2024 Assessment of

Demand Response and Advanced Metering

Staff Report
FEDERAL ENERGY REGULATORY COMMISSION
December 2024

2024 Assessment

of Demand Response and Advanced Metering

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

Staff Report

December 2024

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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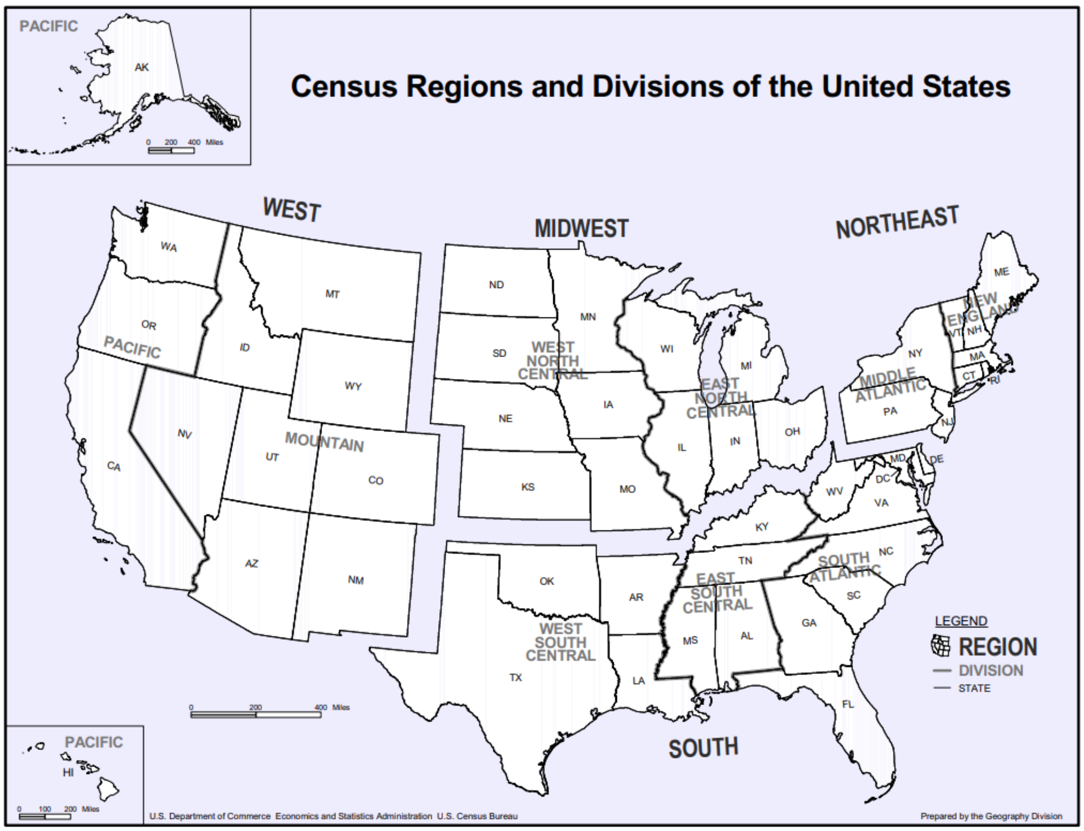
1. Introduction

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

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

Figure 1-1: Map of US Census Divisions



[1] The latest publicly available retail electricity data for the report is for the year 2022 while the latest publicly available wholesale electricity data is for the year 2023.

[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 2021 to 2022, the number of advanced meters[3] in operation in the United States increased by approximately 8 million to a total of 119.3 million, representing a 7.3% annual increase. According to Energy Information Administration (EIA) data, the 119.3 million advanced meters in operation represent over 72% of the 165 million total meters in operation across all customer classes.

- The advanced meter penetration rate continues to vary by Census Division and customer class. For the first time since this report has been published, the nationwide advanced meter penetration rate for the residential customer class was greater than 70%. In the Pacific, South Atlantic, and West South Central Census Divisions, utilities reported aggregate totals of advanced meters that represent advanced meter penetration rates greater than 80% in those regions.

- From 2022 to 2023, demand response participation in the seven U.S. wholesale markets increased slightly by approximately 135 MW, or 0.4%, to a total of 33,055 MW. Demand response totals increased in five of those wholesale markets but declined in two. Approximately 6.5% of the wholesale market peak demand for all RTOs/ISOs could be met by demand response resources in 2023, the same rate as in 2022. The sum of the non-coincident peak demands across all RTOs/ISOs was approximately 512 GW in 2023, compared to 507 GW in 2022.

- State regulators continue to consider and approve proposals to implement different types of time-varying rates and other opportunities to leverage flexible demand. For example, regulators in Colorado, Maine, and Minnesota are either actively evaluating, or have recently approved, retail time of use rates. California recently issued flexible demand appliance standards for swimming pool controls, and the Colorado Commission issued an order approving a virtual power plant (VPP) pilot program.

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

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

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

Other types of meters currently in use—such as standard electromechanical, standard solid state, and automated meter reading (AMR) meters, which collect data for billing purposes only and transmit these data one way—are not considered advanced meters for the purposes of this report. *See* EIA, Form EIA-861: Annual Electric Power Industry Report Instructions at 17-18, http://www.eia.gov/survey/form/eia_861/instructions.pdf.

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

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

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

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

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

2. Saturation and Penetration Rate of Advanced Meters

This chapter presents the national and regional penetration rates of advanced meters in the United States as well as state developments related to grid modernization and advanced metering. Table 2-1 provides estimates of advanced meter penetration rates from 2012 through 2022. According to 2022 EIA data, utilities had installed and were operating 119.3 million advanced meters out of the 165.0 million total meters in the United States. This represents an advanced meter penetration rate of 72.3% and an increase of 8.1 million advanced meters, or 7.3%, from 2021 to 2022. This is the sixth consecutive year that the number of advanced meters has increased by approximately 8 million. The Edison Foundation's Institute of Electric Innovation reported a similar number of advanced meters—120 million—in operation in the United States in 2022.

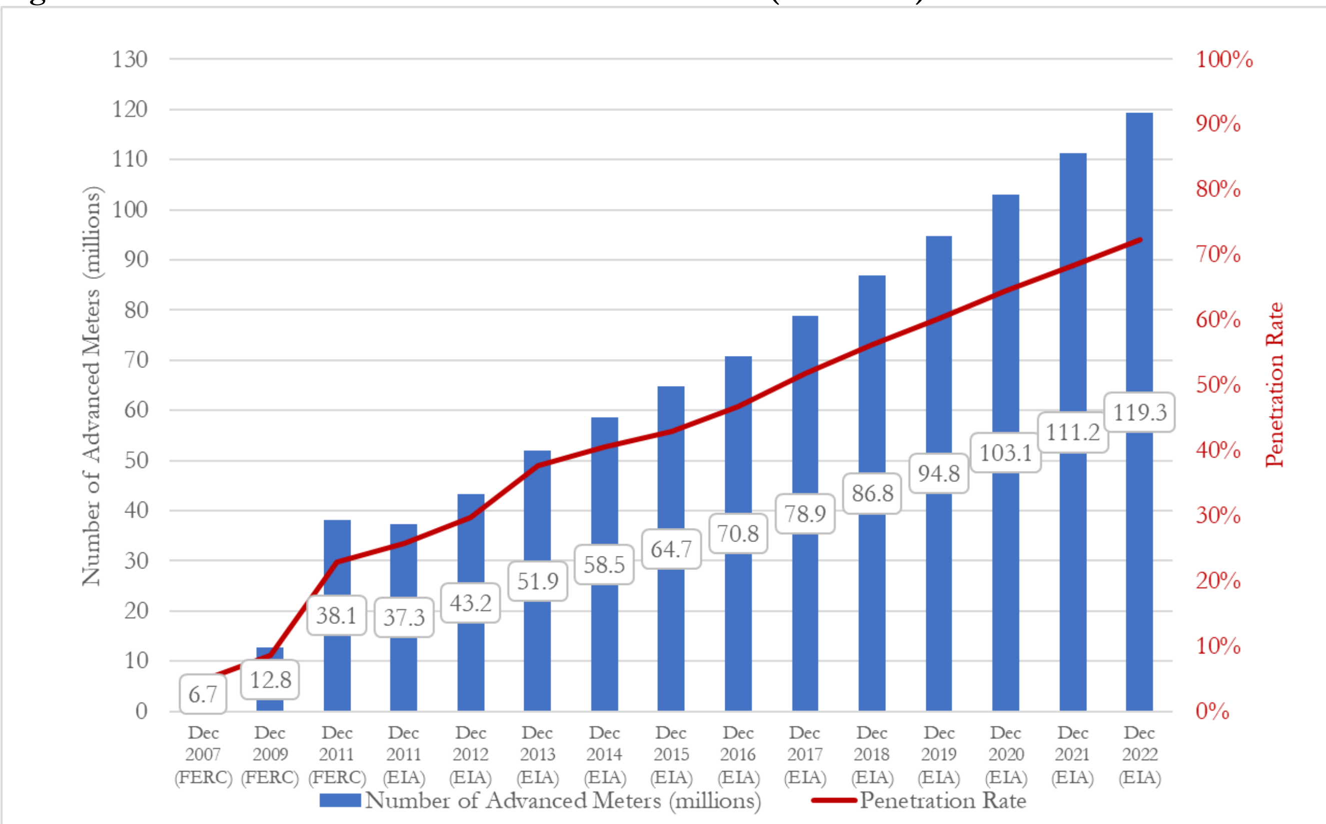
Table 2-1: Estimates of Advanced Meter Penetration Rates in the United States (2012 – 2022)

Data Source	Data as Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2012 Form EIA-861[2]	Dec 2012 (EIA)	43.2	145.3	29.7%
2013 Form EIA-861[2]	Dec 2013 (EIA)	51.9	138.1	37.6%
2014 Form EIA-861[2]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[2]	Dec 2015 (EIA)	64.7	150.8	42.9%
2016 Form EIA-861[2]	Dec 2016 (EIA)	70.8	151.3	46.8%
2017 Form EIA-861[2]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[2]	Dec 2018 (EIA)	86.8	154.1	56.4%
2019 Form EIA-861[2]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[3]	Dec 2019 (IEI)	99.0	157.2	63.0%
2020 Form EIA-861[2]	Dec 2020 (EIA)	103.1	159.7	64.6%
Institute for Electric Innovation[3]	Dec 2020 (IEI)	107.4	159.7	67.2%
2021 Form EIA-861[2]	Dec 2021 (EIA)	111.2	162.8	68.3%
Institute for Electric Innovation[3]	Dec 2021 (IEI)	115.3	162.8	70.8%
2022 Form EIA-861[2]	Dec 2022 (EIA)	119.3	165.0	72.3%
Institute for Electric Innovation[4]	Dec 2022 (IEI)	120.0	165.0	72.3%

Sources: [1]EIA-861 Advanced Meters data files 2012-2022. [2]IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* 2021. [3]IEI, *Smart Meters at a Glance* (2024).
Notes: Commission staff has not independently verified the accuracy of EIA or Edison Foundation (IEI) data. Values from source data are rounded for publication. A table containing the data for 2007 through 2022 is in Appendix II.

Figure 2-1 shows advanced meter growth in the United States from 2007 through 2022. Since 2007, the number of operational advanced meters has increased by 112.6 million, from 6.7 million meters in 2007 to 119.3 million meters in 2022. Over that same period, the advanced meter penetration rate increased from 4.7% to 72.3%.

Figure 2-1: Advanced Meter Growth in the United States (2007–2022)



Sources: FERC, *Assessment of Demand Response and Advanced Metering* 2008-2012; EIA-861 Advanced Meters data files 2011-2022.
Note: The left axis, Number of Advanced Meters (million), corresponds to the blue columns. The right axis, Penetration Rate, corresponds to the red line on the chart.

Table 2-2 below provides estimates of advanced meter penetration rates by Census Division and retail customer class for 2022. Utilities reported aggregate totals of advanced meters that represent penetration rates above 80% in three of the nine Census Divisions – Pacific, South Atlantic, and West South Central. 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 87.0%, the highest rate reported by utilities in any Census Division. In contrast, utilities in the Middle Atlantic and New England Census Divisions reported totals representing aggregate advanced meter penetration rates below 50%.

Table 2-2 also shows the overall advanced meter penetration rate for the residential, commercial, and industrial customer classes. The total advanced meter penetration rate across all regions for each of the customer classes was greater than 65%. Overall, utilities reported the highest number of advanced meters in the residential class, which registered a penetration rate of 72.7%. Closely following this reported total, the commercial and industrial customer classes registered advanced meter penetration rates of 69.3% and

68.5%, respectively. However, the advanced meter penetration rates for each customer class varied among Census Divisions. For example, the residential customer class had the highest advanced meter penetration rates in the East North Central, East South Central, South Atlantic, and West South Central Census Divisions. The commercial customer class had advanced meter penetration rates above 80% in the Pacific, South Atlantic, and West South Central Census Divisions. The industrial customer class had advance meter penetration rates above 70% in the East North Central, East South Central, West North Central, and West South Central Census Divisions.

Table 2-2: Advanced Meter Penetration Rate by Census Division and Customer Class (2022)

Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	79.5%	76.2%	70.2%	79.1%
East South Central	80.3%	75.4%	70.2%	79.6%
Middle Atlantic	44.0%	42.5%	55.4%	43.9%
Mountain	65.4%	55.6%	68.4%	64.2%
New England	23.3%	24.0%	23.3%	23.4%
Pacific	80.7%	81.5%	69.1%	80.9%
South Atlantic	86.4%	83.9%	62.1%	86.0%
West North Central	58.6%	55.2%	72.8%	58.3%
West South Central	87.8%	82.1%	75.2%	87.0%
All Regions	**72.7%**	**69.3%**	**68.5%**	**72.3%**

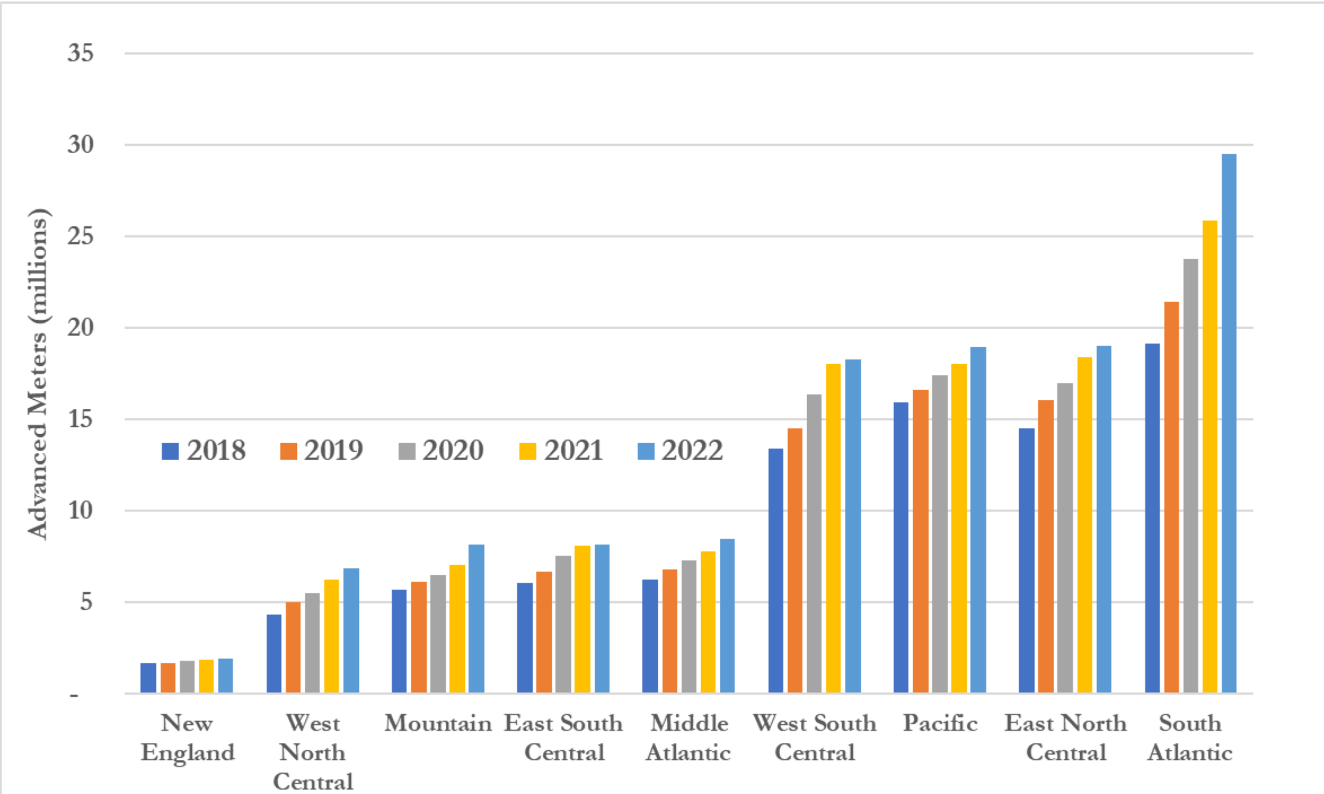
Sources: 2022 Form EIA-861 Advanced_Meters_2022 data file and 2022 Form EIA-861 Utility_Data_2022 data file.
Notes: Transportation sector data collected by EIA contain a relatively small number of meters and are not reported separately here. Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data.

Figure 2-2 shows the number of advanced meters in operation by Census Division from 2018 to 2022. Over this period, the number of advanced meters showed an upward trend across all Census Divisions. Utilities in all nine Census Divisions reported more advanced meters in operation in 2022 compared with 2021. The South Atlantic Census Division experienced the largest increase in the number of advanced meters from 2021 to 2022, where utilities reported just over 3.6 million more advanced meters, an increase of 14%. Within the South Atlantic Census Division, the utilities that reported the largest increases in the number of advanced meters include Virginia Electric & Power Co in Virginia, Florida Power and Light Co., and Jacksonville, Florida-based JEA, which reported more than 686,000, 552,000, and 205,000 additional advanced meters in 2022, respectively.

The Mountain Census Division experienced the largest percentage increase in the number of advanced meters from 2021 to 2022, where utilities reported approximately 1.1 million more advanced meters, representing an increase of 15%. Public Service Co. of Colorado, PacifiCorp in Utah, and PacifiCorp in Idaho saw the largest increases in the Mountain Census Division, reporting more than 409,000, 163,000, and 85,000 additional advanced meters in 2022 compared to 2021, respectively.

Over the same period, utilities also installed more advanced meters in the Pacific (944,000 new meters), Middle Atlantic (725,000), East North Central (665,000), West North Central (607,000), West South Central (240,000), New England (100,000), and East South Central (98,000) Census Divisions.

Figure 2-2: Number of Advanced Meters by Census Division (2018 – 2022)



Sources: EIA-861 Advanced Meters data files 2018 – 2022.

Development and Issues in Advanced Metering

State Legislative and Regulatory Activities Related to Advanced Metering

Several states have taken actions related to advanced metering infrastructure (AMI). We discuss some of those actions here.

Connecticut. On January 3, 2024, the Connecticut Public Utilities Regulatory Authority (PURA) issued an order in its investigation into AMI in the context of distribution utility system planning.[4] The order is an outgrowth of a 2019 initiative by the PURA intended to accelerate the modernization of the electric grid in an innovative, cost-effective, and equitable manner.[5] The order identifies deployment and effective use of AMI as one of four key objectives needed to achieve a modernized grid. To meet this objective, the PURA determined that it needs to: (1) provide a regulatory roadmap for utilities; (2) protect ratepayers; and (3) ensure that any investment in AMI advances the economic, energy, and environmental policy goals of the state. Specifically, the order adopts a framework that incorporates specific goals for AMI, including the design and procurement practices and investment strategy needed to deploy AMI in a prudent, transparent, and effective manner; and establishes the metrics to measure the value of AMI to customers. With the adoption of this framework, the PURA authorized Connecticut utilities to proceed or continue with their deployment of AMI and to recoup the costs in retail rates. In addition, the PURA also concluded that customers need easy access and control of their meter data to benefit from the AMI investment.[6] Therefore, the PURA established several key requirements for data access and sharing.

Kentucky. On January 19, 2024, Jackson Purchase Energy Corporation (Jackson Purchase) filed an application with the Kentucky Public Service Commission (KYPSC) to install a new AMI system.[7] In its application, Jackson Purchase explains that it is seeking to replace its old AMI system because of its inability to receive monthly billing reads and the continued deterioration of meter read rates.[8] The installation of the new advanced meters will take approximately two years to finish. Jackson Purchase estimates that AMI

[4] *PURA Investigation into Distribution System Planning of The Electric Distribution Companies – Advanced Metering Infrastructure,* Docket No. 17-12-03RE02 (Connecticut Public Utilities Regulatory Authority January 3, 2024), Decision (state.ct.us).

[5] *Id.* at 1.

[6] *Id.* at 39.

[7] *Electronic Application of Jackson Purchase Energy Corporation For a Certificate Of Public Convenience and Necessity Authorizing the Installation of a New Advanced Metering Infrastructure (AMI) System*, Docket No: 2024-00013 (Kentucky Public Service Commission Jan. 19, 2024), https://psc.ky.gov/Case/ViewCaseFilings/2024-00013.

[8] *Electronic Application of Jackson Purchase Energy Corporation for a Certificate of Public Convenience and Necessity Authorizing the Installation of a New Advanced Metering Infrastructure (AMI) System*, Docket No: 2024-00013, at 3 (Kentucky Public Service Commission January 26, 2024), https://psc.ky.gov/pscecf/2024-00013/heather%40hloky.com/01262024041401/AMI_CPCN_App_w_Exh_FINAL.pdf.

installation will reduce the operating expense of its metering system due mainly to a decrease in manual meter readings.

Massachusetts. On April 24, 2024, the Massachusetts Department of Public Utilities (DPU) issued an order addressing the first annual filing of Massachusetts Electric Company and Nantucket Electric Company, two subsidiaries of National Grid, to recover the costs associated with their installation of AMI meters.[9] The order explains that when the DPU approved National Grid's 2022-2025 grid modernization plan in 2022, it also included the company's 2023-2027 AMI implementation plan.[10] At the time, the DPU established cost recovery for eligible AMI investment in the prior year, as well as any prior reconciliation costs and some other costs.[11] The investments eligible for recovery are those that are necessary to install and enable AMI's ability to produce granular customer data, voltage or other grid-facing data, or that use AMI data to provide broad customer and system benefits.[12]

The April 2024 order was the DPU's first annual AMI cost prudency review for National Grid's two Massachusetts electric utilities. In it, the DPU permitted the AMI cost recovery to go into effect subject to future reconciliation and further process.[13]

South Dakota. On September 8, 2023, Otter Tail Power Company submitted to the South Dakota Public Utilities Commission (South Dakota PUC) a proposed administrative tariff and brochure revisions to facilitate implementation of new Advanced Grid Infrastructure projects. Otter Tail proposed an effective date of January 1, 2024 and asked the South Dakota PUC to disallow customers from opting-out of AMI meters. The South Dakota PUC approved these revisions for the effective date of January 1, 2024.[14]

Collaborative Industry-Government Efforts

Department of Energy. The U.S. Department of Energy's (DOE) Grid Resilience and Innovation Partnerships (GRIP) Program supports AMI technology as part of its support for a wide variety of

[9] *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval by the Department of Public Utilities of its Advanced Metering Infrastructure Factors*, Docket No. 24-38, at 1 (Mass. Department of Public Utilities April 24, 2024).

[10] *Id.* at 2.

[11] *Id.* at 2

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

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

[14] *In the Matter of Otter Tail Power Company's Petition for Approval of Tariff Revisions to Facilitate Implementation of New Advanced Grid Infrastructure (AGI) Projects, Docket No. EL23-027* (South Dakota PUC December 7, 2023) at 2, https://puc.sd.gov/commission/dockets/electric/2023/el23-027/EL23-027TariffRev.pdf.

investments intended to enhance grid flexibility and improve the resilience of the power system.[15] The program includes three funding mechanisms: Grid Resilience Utility and Industry Grants, Smart Grid Grants, and the Grid Innovation Program. Several of the GRIP Program projects selected to receive Smart Grid Grants incorporate the deployment of AMI technology.[16] For example, Arkansas Valley Electric Cooperative Corporation plans to use Smart Grid Grant funding to install grid-enhancing technologies, including AMI, to improve the reliability of its distribution system, reduce grid maintenance costs and environmental impacts, and improve worker safety.[17] Similarly, Rappahannock Electric Cooperative in Virginia will deploy AMI upgrades, a distributed energy resources management system (DERMS), and a fiber utility network.[18] AMI will enable Rappahannock Electric Cooperative customers to make data-informed behavioral changes, to maximize energy efficiency and reduce peak demand, and will provide flexibility for customers to access time-varying pricing programs. Liberty Utilities, LLC (CalPeco Electric) in northern California intends to install smart meters and upgrade network infrastructure and software to enable remote meter reading, outage management, event automation, and distributed intelligence.[19] The proposed upgrades would help reduce the impact and duration of fire-related outages by enabling faster response times and mitigation. On November 14, 2023, DOE announced a second funding opportunity for the GRIP Program with selected projects to be announced in late 2024.[20]

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[15] DOE, *Biden-Harris Administration Announces $3.5 Billion for Largest Ever Investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs* (Oct. 2023), https://www.energy.gov/articles/biden-harris-administration-announces-35-billion-largest-ever-investment-americas-electric.

[16] DOE Grid Deployment Office, *Grid Resilience and Innovation Partnerships (GRIP) Program Projects*, https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects

[17] DOE Grid Deployment Office, *GRIP Program Fact Sheet: Improving Grid Efficiency, Reliability, and Flexibility in Arkansas*, https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2041_Arkansas%20Valley%20Electric%20Cooperative%20Corporation_v4_RELEASE_508.pdf.

[18] DOE Grid Deployment Office, *GRIP Program Fact Sheet: Advancing Clean, Reliable Energy within the Rappahannock Electric Cooperative*, https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2047_Rappahannock%20Electric%20Cooperative_v4_RELEASE_508.pdf.

[19] DOE Grid Deployment Office, *GRIP Program Fact Sheet: Project Leapfrog*, https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2102_Liberty%20Utilities%20%28CalPeco%20Electric%29%2C%20LLC_v4_RELEASE_508.pdf.

[20] DOE Grid Deployment Office, *Biden-Harris Administration Announces Up to $3.9 Billion to Modernize and Expand America's Power Grid* (Nov. 2023), https://www.energy.gov/gdo/articles/biden-harris-administration-announces-39-billion-modernize-and-expand-americas-power.

3. Annual Resource Contribution of Demand Resources

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

Retail Demand Response Programs

Table 3-1 below provides annual potential peak demand savings for 2021 and 2022 from retail demand response programs in each of the nine Census Divisions. The term "potential peak demand savings" refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called."[21] Potential peak demand savings in the United States increased by 1,225 MW, or 4.2%, from 29,222 MW in 2021 to 30,448 MW in 2022. On a regional basis, annual peak demand savings increased in all but two Census Divisions from 2021 to 2022.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2022 and 2021)

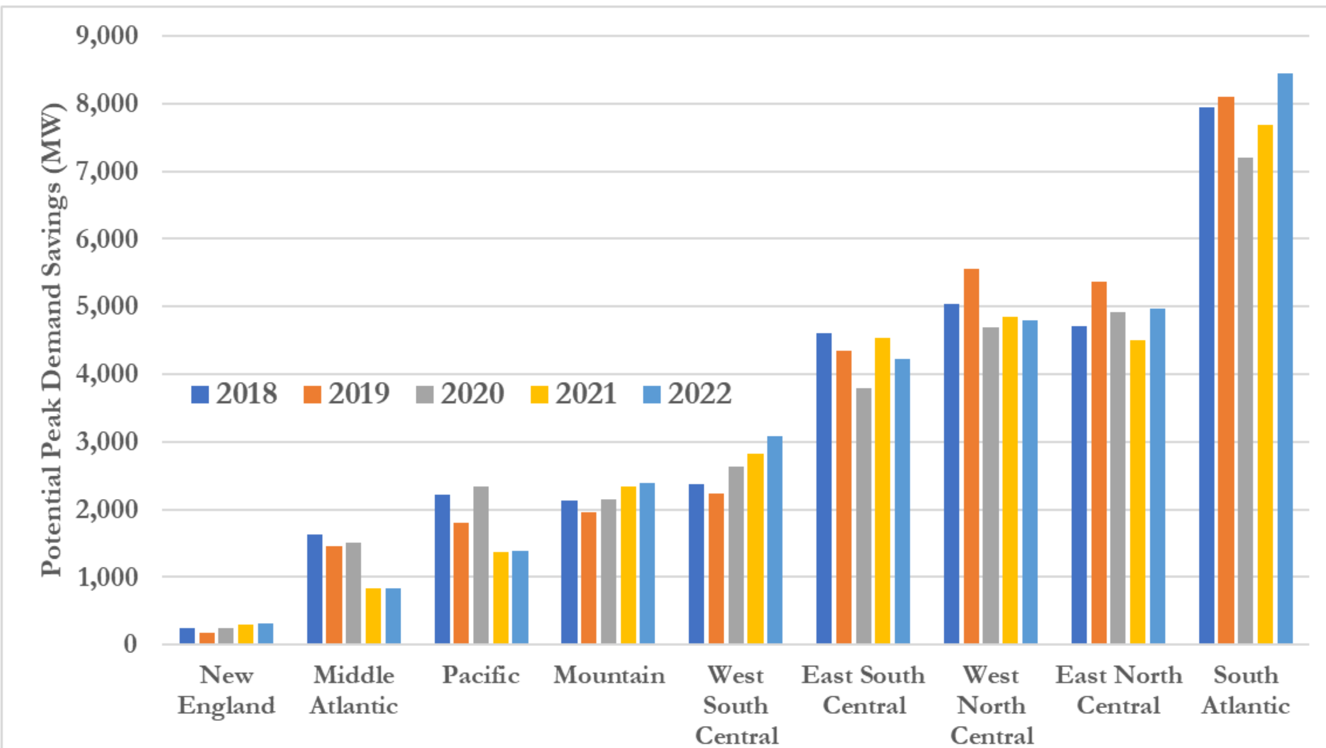
Census Division	Annual Potential Peak Demand Savings (MW)		Year-over-Year Change	
	2021	2022	MW	%
East North Central	4,500.2	4,974.0	473.8	10.5%
East South Central	4,536.8	4,223.4	-313.5	-6.9%
Middle Atlantic	837.7	842.1	4.4	0.5%
Mountain	2,336.8	2,389.4	52.6	2.2%
New England	293.8	309.2	15.4	5.2%
Pacific	1,377.1	1,390.3	13.1	1.0%
South Atlantic	7,678.7	8,449.2	770.5	10.0%
West North Central	4,840.2	4,787.4	-52.8	-1.1%
West South Central	2,820.8	3,082.6	261.8	9.3%
Total	**29,222.2**	**30,447.6**	**1,225.4**	**4.2%**

Sources: 2022 Form EIA-861 Utility_Data_2022 data file, 2022 Form EIA-861 Demand_Response_2022 data file, 2021 Form EIA-861 Utility_Data_2021 data file, 2021 Form EIA-861 Demand_Response_2021 data file.
Notes: 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. Values from source data are rounded for publication

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

Figure 3-1 below shows changes in potential peak demand savings from retail demand response programs in each Census division from 2018 through 2022. Over this period, the amount of potential peak demand savings varied significantly for each Census Division. From 2021 to 2022, utilities in seven of the nine Census Divisions experienced increases in potential peak demand savings. In aggregate, utilities in the South Atlantic Census Division reported approximately 771 MW, or 10.0%, more potential peak demand savings in 2022, the largest increase among Census Divisions. Utilities in the South Atlantic Census Division with notable potential peak demand savings increases include Duke Energy Carolinas in North Carolina and South Carolina Public Service Authority (Santee Cooper), which reported approximately 123 MW and 59 MW of additional peak demands savings, respectively.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2018 – 2022)



Sources: EIA-861 Demand Response data files 2018 – 2022.

Utilities in other Census Divisions also experienced notable increases. In the East North Central Census Division, Consumers Energy Co. and DTE Electric Co., both in Michigan, reported approximately 177 MW and 44 MW more potential peak demand savings in 2022 than 2021, respectively. Entergy Arkansas and Oklahoma Gas & Electric in Oklahoma reported 91 MW and 59 MW more potential peak demand savings in the West South Central Census Division, respectively. In the Mountain Census Division, the largest increases were from Arizona Public Service Co., PacifiCorp in Utah, and Public Service Co. of Colorado, which reported approximately 55 MW, 39 MW, and 34 MW more potential peak demand savings, respectively. Portland General Electric Co. and San Diego Gas & Electric Co. in the Pacific Census Division reported approximately 19 MW and 15 MW more potential peak demand savings, respectively. Finally, Consolidated Edison Co. in the Middle Atlantic Census Division and Connecticut Light & Power

Co. in the New England Census Division reported 33 MW and 16 MW of additional potential peak demand savings, respectively.

While potential peak demand savings increased nationwide, the East South Central and West North Central Census Divisions experienced small aggregate decreases in potential peak demand savings from 2021 to 2022. In aggregate, utilities in the East South Central Census Division reported approximately 314 MW, or 7%, less potential peak demand savings, while utilities in the West North Central Census Division reported approximately 53 MW, or 1.1%, less potential peak demand savings in 2022 compared with 2021. The decline in the East South Central Census Division came from one cooperative that reported 754 MW fewer potential peak demand savings, while the decline in the West North Central Census Division was the result of several utilities experiencing decreases.

Table 3-2 below shows the relative contribution of retail potential peak demand savings from the residential, commercial, and industrial customer classes in 2022. Utilities continue to report the largest potential peak demand savings—approximately 14,864 MW—is attributed to the industrial class, representing roughly half of the total reported potential peak demand savings. The relative contributions to potential peak demand savings by the residential and commercial customer classes are slightly more than those reported in 2021, with the residential and commercial classes accounting for approximately 30% and 21% of the total 2022 potential peak demand savings, respectively. The customer class with the largest amount of potential peak demand savings varied among Census Divisions. The residential class had the largest amount of potential peak demand savings in the Mountain, South Atlantic, and West North Central Census Divisions. The commercial class had the largest amounts of potential peak demand savings in the Middle Atlantic and New England Census Divisions. The industrial class had the largest amounts of potential peak demand savings in the East North Central, East South Central, Pacific, and West South Central Census Divisions.

Table 3-2: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division and Customer Class (2022)

Census Division	Customer Class			
	Residential (MW)	Commercial (MW)	Industrial (MW)	All Classes (MW)
East North Central	837.7	888.2	3,248.1	4,974.0
East South Central	343.5	117.9	3,761.9	4,223.4
Middle Atlantic	169.8	536.6	135.8	842.1
Mountain	1,169.9	365.3	854.3	2,389.4
New England	110.0	132.5	66.7	309.2
Pacific	404.9	303.2	682.2	1,390.3
South Atlantic	3,476.9	2,393.3	2,579.1	8,449.2
West North Central	1,981.0	1,005.6	1,800.8	4,787.4
West South Central	545.3	802.2	1,735.1	3,082.6
Total	**9,038.9**	**6,544.7**	**14,864.0**	**30,447.6**

Sources: 2022 Form EIA-861 Demand_Response_2022 data file and 2022 Form EIA-861 Utility_Data_2022 data file.
Notes: 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. Values from source data are rounded for publication.

Wholesale Demand Response Programs

Table 3-3 below estimates participation in the seven RTO/ISO[22] wholesale demand response programs in 2022 and 2023. Demand response participation in the wholesale markets overall increased slightly by approximately 135 MW, or 0.4%, from 2022 to 2023. On a regional basis, demand response totals increased in five of the wholesale markets but declined in two of them. SPP experienced the largest annual increase among RTOs/ISOs, reporting approximately 431 MW more demand response resource capability in 2023. Based on the reported data, approximately 6.5% of the wholesale market non-coincident peak demand for all RTOs/ISOs could be met by demand response resources in 2023, the same rate as in 2022. The sum of the non-coincident peak demands across all RTOs/ISOs was approximately 512 GW in 2023.

In CAISO, demand response resources increased by approximately 199 MW, or 5%, from 3,956 MW in 2022 to 4,154 MW in 2023. Third party demand response capability averaged 210 MW in 2023, which was down 14% from 2022.[23] Third party demand response is operated by non-utility providers under contract to supply demand response for utilities. Similarly, utility demand response capability declined by 9% from 2022, averaging 1,175 MW in 2023.

ERCOT experienced an increase in demand response resources of approximately 51 MW, or 1.4%, from 3,562 MW in 2022 to 3,613 MW in 2023. From 2022 to 2023, demand response resources participating ERCOT's in the Responsive Reserve Service (RRS) program decreased by 278 MW, while resources providing Emergency Response Service increased by 76 MW. The RRS program allows resources controlled by high-set under-frequency relays to provide reserve service. In June 2023, ERCOT launched a new ancillary service, the ERCOT Contingency Reserve Service (ECRS).[24] In contrast to the RRS, the ECRS program allows load resources that do or do not have under-frequency relays to provide this reserve service.[25] ECRS-deployed resources must respond within ten minutes and return to pre-deployment conditions within three hours. ERCOT reported approximately 178 MW of average hourly ECRS offers in August 2023, the month with the highest peak demand in ERCOT for that year. ERCOT also reported load resources participating for the first time in non-spinning reserve service which offered an average of 75 MW per hour in August 2023.[26]

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[22] 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).

[23] CAISO, *2023 Annual Report on Market Issues & Performance* at 37 (Jul. 2024), https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf.

[24] ERCOT, *ERCOT Adds New Ancillary Service to Support Grid Reliability* (Jun 2023), https://www.ercot.com/news/release/2023-06-12-ercot-adds-new .

[25] *See* ERCOT, *2023 Annual Reports of Demand Response in the ERCOT Region* at 5 (Dec. 2023), https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=975814860.

[26] *Id.* at 4.

Table 3-3: Demand Response Resource Participation in RTOs/ISOs (2022 & 2023)

RTO/ISO	2022		2023		Year-over-Year Change	
	Demand Response Resources (MW)	Percent of Peak Demand[8]	Demand Response Resources (MW)	Percent of Peak Demand[8]	MW	Percent
CAISO[1]	3,955.8	7.6%	4,154.3	9.3%	198.5	5.0%
ERCOT[2]	3,561.6	4.4%	3,612.8	4.2%	51.1	1.4%
ISO-NE[3]	573.0	2.3%	456.0	1.9%	-117.0	-20.4%
MISO[4]	12,390.0	10.2%	12,663.0	10.1%	273.0	2.2%
NYISO[5]	1,483.3	4.9%	1,708.7	5.5%	225.4	15.2%
PJM[6]	10,594.6	7.3%	9,666.8	6.7%	-927.8	-8.8%
SPP[7]	361.8	0.7%	793.0	1.4%	431.2	119.2%
Total	**32,920.1**	**6.5%**	**33,054.5**	**6.5%**	**134.5**	**0.4%**

Sources for demand resource data: [1] CAISO, 2022 and 2023 Annual Reports on Market Issues and Performance. Totals for Figure 1.33 were confirmed with the CAISO Department of Market Monitoring; [2] Estimated based on ERCOT, 2022 and 2023 Annual Reports of Demand Response in the ERCOT Region; [3] ISO-NE Monthly Market Operations Report July 2023 and April 2024; [4] Potomac Economics, 2022 and 2023 State of the Market Reports for the MISO Electricity Markets; [5] NYISO, 2022 and 2023 Annual Reports on Demand Response Programs; [6] PJM, 2022 and 2023 Demand Response Operations Markets Activity Reports. Totals represent "unique MW" (see footnote 41); [7] SPP, 2022 and 2023 State of the Market Reports; [8] Sources for peak demand data: CAISO 2022 and 2023 Annual Reports on Market Issues and Performance; ERCOT 2022 & 2023 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report; Potomac Economics, 2022 and 2023 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2022 and 2023; 2022 and 2023 PJM State of the Market Report, Vol. 2; SPP 2022 and 2023 State of the Market Reports.
Notes: Commission staff has not independently verified the accuracy of the data from the sources listed. Values from source data are rounded for publication.

ISO-NE reported approximately 456 MW of Active Demand Capacity Resources enrolled in September 2023, the month with the highest peak demand in ISO-NE. This represents a 117 MW, or 20.4%, decrease from the 573 MW of Active Demand Capacity Resources enrolled in August 2022, the month with the highest peak demand in ISO-NE in 2022.

In MISO, demand response resource capability increased by approximately 273 MW, or 2.2%, from 12,390 MW in 2022 to 12,663 MW in 2023. From 2022 to 2023, Load Modifying Resource[27] capability increased by 112 MW. Emergency Demand Response capability also increased by 427 MW. In contrast, Demand

[27] Load Modifying Resources (LMRs) are Demand or Behind the Meter Generation resources that are available to MISO to meet its resource adequacy requirements and can be called up by MISO during a capacity or transmission emergency. *See* MISO, *Resource Adequacy Business Practice Manual* at 15 (Oct. 2023), https://cdn.misoenergy.org/BPM-011%20Resource%20Adequacy110405.zip

Response Resource Type I and II capability decreased by 109 MW.[28] Demand Response Type I and II resources can participate in MISO's capacity, energy, and ancillary services markets.

NYISO experienced an increase in demand response resource capability of approximately 225 MW, or 15.2%, from 1,483 MW in 2022 to 1,709 MW in 2023. From 2022 to 2023, enrollment in NYISO's reliability-based demand response programs increased by 60 MW.[29] Enrollment also increased in NYISO's economic-based Demand-Side Ancillary Service Program by 165 MW. No offers have been submitted by resources in NYISO's other economic-based program, the Day-Ahead Demand Response Program, since December 2010.[30]

In PJM, demand response resources decreased by approximately 928 MW, or 8.8%, from 10,595 MW in 2022 to 9,667 MW in 2023. The decrease in demand response participation reflects decreased participation in the Load Management and Price Responsive Demand programs. From 2022 to 2023, enrollment in Load Management programs decreased by approximately 871 MW. No resource participation was reported for the Price Responsive Demand program in 2023, resulting in a decrease of approximately 443 MW. However, PJM experienced an increase of approximately 371 MW of demand response participation in its Economic programs.[31]

SPP experienced the largest net annual increase in demand response resources. From 2022 to 2023, the total demand response capability increased by approximately 431 MW, or 119.2%, from 362 MW in 2022 to 793 MW in 2023. In 2023, 64 demand response resources retired from SPP, representing 25 MW of nameplate capacity; however, 56 demand response resources were added with a total of 449 MW.[32]

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[28] The values reported for Demand Response Type I and II, and Emergency Demand Response may include resources cross-registered as Load Modifying Resources. *See* Potomac Economics, *2023 State of the Market Report for the MISO Electricity Markets* at 92 (Jun. 2024), https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf.

[29] NYISO's reliability-based demand response programs include the Emergency Demand Response Program and the Installed Capacity – Special Case Resource program. *See* NYISO, *2023 Annual Report on Demand Response Programs* at 1-2 (Feb. 2024), https://www.nyiso.com/documents/20142/43322405/NYISO-2023-Annual-Report-on-Demand-Response-Programs.pdf/7db01a72-f317-380e-ded1-3f7d8bf88a96.

[30] *Id.* at 20.

[31] The values reported for Economic and Load Management programs may include resources registered to participate in both programs. The total demand response resource participation reported here represents "unique MW." According to PJM, unique MW "represent total estimated demand reduction assuming full Load Management and Economic reductions." *See* PJM, 2023 *Demand Response Operations Markets Activity Report* at 3 (Apr. 2024), https://www.pjm.com/-/media/markets-ops/dsr/2023-demand-response-activity-report.ashx.

[32] SPP, *State of the Market 2023* at 45 (May 2024), https://www.spp.org/documents/71645/2023%20annual%20state%20of%20the%20market%20report%20v2.pdf.

Demand Response Deployments

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

On July 20, 2023, CAISO issued an Energy Emergency Alert Level 1 (EEA 1) due to heat conditions and higher-than-anticipated demand.[33] In response, CAISO dispatched 850 MW of reliability demand response resources (RDRR).[34] On June 29, 2023, the California Public Utilities Commission (CPUC) clarified that CAISO could dispatch RDRRs when an EEA Watch or higher is declared.[35] Prior to this, CAISO could only dispatch reliability demand response under EEA 2 or higher. CAISO notes that the performance of RDRRs averaged 71% during high load summer days.[36]

On September 6, 2023, ERCOT issued an EEA 2 and deployed demand response resources to ensure reliable operations.[37] The event resulted in the deployment of 113.4 MW of ECRS and 1,482 MW of RRS. ERCOT also deployed ERS twice in 2023, with 35 MW deployed on August 17 and approximately 995 MW deployed on September 6.[38] ERCOT reported an ERS performance of 120% for the August 17 event and 93.7% for the September 6 event.

[33] CAISO, *News Release: Energy Emergency Alert (EEA) 1 Declared and Ended* (Jul. 2023), https://www.caiso.com/documents/energy-emergency-alert-eea-1-declared-and-ended.pdf.

[34] CASIO, *Summer Market Performance Report* at 13-14 (Jul. 2023), https://www.caiso.com/Documents/Summer-Market-Performance-Report-for-July-2023.pdf.

[35] *Decision Adopting Local Capacity Obligations for 2024 - 2026, Flexible Capacity Obligations For 2024, and Program Refinements*, Decision 23-06-029 (CPUC June 29, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M513/K132/513132432.PDF.

[36] Here, performance represents resource curtailments, including curtailments above individual resource's schedules, as a percentage of their scheduled curtailments. *See* CAISO, *Demand Response Issues and Performance 2023* at 16 (Mar. 2024), https://www.caiso.com/documents/demand-response-report-2023-mar-6-2024.pdf.

[37] ERCOT, *2023 Annual Reports of Demand Response in the ERCOT Region* at 6 (Dec. 2023), https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=975814860. *See also* ERCOT, *ERCOT Has Initiated Energy Emergency Alert Level 2 (EEA 2), Conservation is Critical* (Sept. 2023), https://www.ercot.com/news/release/2023-09-06-ercot-has-initiated.

[38] Here, performance represents resources' response as a percentage of their obligation. *See* ERCOT, *2023 Annual Reports of Demand Response in the ERCOT Region* at 6 (Dec. 2023) at 12.

NYISO activated its Targeted Demand Response Program (TDRP) in response to a transmission owner request on August 21, 2023.[39] The TDRP is a reliability-based demand response program, only available in the New York City load zone, that deploys demand response resources on a voluntary basis to solve local reliability problems at the request of a transmission owner.[40] The August 21 request resulted in a total response of 15.5 MW.[41] NYISO did not activate its other reliability-based demand response programs for events during the 2023 winter and summer periods.[42]

[39] NYISO, *2023 Annual Report on Demand Response Programs* at 18 (Feb. 2024), https://www.nyiso.com/documents/20142/43322405/NYISO-2023-Annual-Report-on-Demand-Response-Programs.pdf/7db01a72-f317-380e-ded1-3f7d8bf88a96.

[40] *Id.* at 2.

[41] *Id.* at 19.

[42] *Id.* at 13.

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

This chapter summarizes selected recent federal and industry publications which assess the potential for demand response as a quantifiable, reliable resource for regional planning purposes.

In April 2024, the U.S. Department of Energy (DOE) published a report that outlines several technology solutions for addressing resource adequacy needs.[43] In the report, DOE explains that an approach that uses a portfolio of technology solutions best ensures reliable, clean, secure, and affordable power.[44] Among the list of technologies, DOE includes demand flexibility and distributed energy resources (DERs). The report states that demand flexibility can contribute to resource adequacy when retail customers respond to time-varying rates that provide incentives to shift load to non-peak hours, thereby reducing demand and providing effective capacity.[45] It also states that DERs providing demand flexibility through demand response programs can be managed through various means, such as through managed electric vehicle (EV) chargers, smart thermostats, and other programs. According to the report, aggregations of DERs called virtual power plants (VPPs) can balance electrical loads and provide utility-scale and utility-grade grid services like traditional power plants, including boosting resource adequacy.[46] In a separate report published in September 2023, DOE detailed pathways for commercialization of VPPs (*VPP Liftoff Report*).[47] DOE estimates the current national VPP capacity to range between 30-60 GW.[48] DOE states that tripling VPP capacity to 80-160 GW by 2030 could meet 10-20% of peak demand[49] and save an estimated $10 billion per year in grid costs. DOE explains that VPPs face hurdles to deployment despite their financial and grid benefits. Some of the regulatory barriers to VPP deployment are discussed further in Chapter 6.

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[43] DOE, *The Future of Resource Adequacy* (Apr. 2024), https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.

[44] *Id.* at 3.

[45] *Id.* at 24.

[46] *Id. See also DOE, The Pathway to: Virtual Power Plants Commercial Liftoff,* https://liftoff.energy.gov/vpp/.

[47] DOE, *Pathways to Commercial Liftoff: Virtual Power Plants* (Sept. 2023) (*VPP Liftoff Report*), https://liftoff.energy.gov/wp-content/uploads/2023/09/20230911-Pathways-to-Commercial-Liftoff-Virtual-Power-Plants_update.pdf.

[48] *Id.* at 13.

[49] DOE estimates that between 2023 and 2030, the U.S. grid will likely need to add enough new capacity to supply over 200 GW of electricity demand during peak hours. *See Id.* at 33.

In April 2024, The Brattle Group (Brattle) released a report that explores the market potential for VPPs in California.[50] The report examines how VPP technologies such as smart thermostat-based air conditioning control, behind-the-meter batteries, residential electric vehicle charging, grid-interactive water heating, and automated demand response systems for large commercial buildings and industrial facilities can provide cost savings, reliability benefits, and reduce forecasting and interconnection risks. Brattle found that California's 2035 VPP market potential is over 7,500 MW, representing more than 15% of peak demand in the state.[51] Brattle notes that this is roughly five time larger than the demand response capacity currently used for resource adequacy in California, which it estimates at approximately 1,600 MW. Brattle also projected that by 2035, VPPs in California could produce over $750 million per year in avoided traditional power plant investment, with approximately $550 million of the savings retained by consumers.[52] With respect to automated demand response from commercial and industrial customers, Brattle found that the technology could provide 1,178 MW, or 2.3% of peak demand, in 2035 and produce $94 million per year in avoided system costs.[53] Though not the focus of the study, Brattle also explains that VPPs can reduce risks associated with interconnection delays since they can be deployed quickly and can scale as demand grows, thereby mitigating risks due to uncertainty in demand forecasts.[54] Brattle identifies several barriers that it concludes need to be addressed for VPP potential in California to be fully realized.[55] Barriers facing utilities and load serving entities include participant engagement, regulatory models, and operational experience. Barriers facing third-party providers of VPPs include market uncertainty, data access, and non-comprehensive evaluations of VPP benefits.

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[50] Brattle, *California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability* (Apr. 2024), https://www.brattle.com/wp-content/uploads/2024/04/Californias-Virtual-Power-Potential-How-Five-Consumer-Technologies-Could-Improve-the-States-Energy-Affordability.pdf.

[51] *Id.* at 21.

[52] *Id.* at 22.

[53] *Id.* at 38.

[54] *Id.* at 6.

[55] *Id.* at 40.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter presents regional information on retail demand response[56] and dynamic pricing[57] programs, based on EIA data. From 2021 to 2022, utilities in some regions reported significant increases in the number of customers enrolled in demand response and dynamic pricing programs. As mentioned in previous reports, this continuing trend suggests that utilities are focusing on increasing enrollment in programs that leverage their advanced meter investments. This chapter also summarizes selected recent federal, regional, state, and industry actions and developments related to demand response.[58]

Enrollment in Retail Demand Response and Dynamic Pricing

Table 5-1 shows enrollment by customer account in retail incentive-based demand response programs for each of the nine Census Divisions in 2021 and 2022. Customer enrollment in retail incentive-based demand response programs in the United States decreased slightly by approximately 173,000 customers, or 1.6%, from 10.5 million customers in 2021 to 10.3 million customers in 2022. This drop can be attributed to enrollment declines reported by utilities in the Pacific and South Atlantic Census Divisions.

[56] Demand-side management (DSM) programs are designed to modify patterns of electricity usage, including the timing and level of electricity demand. DSM programs include direct load control, interruptible, demand bidding/buyback, emergency demand response, capacity market, and ancillary service market programs. Previously, EIA referred to these programs as "incentive-based" demand response programs. *See* EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; EIA, *Form EIA-861 Annual Electric Power Industry Report Instructions,* Schedule 6 Part B, https://www.eia.gov/survey/form/eia_861/instructions.pdf; and FERC, *A National Assessment of Demand Response Potential* (2009), https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response.pdf.

[57] Dynamic pricing programs, also known as time-based rate programs, are designed to modify patterns of electricity usage, including the timing and level of electricity demand. They include time-of-use prices, as well as real-time pricing, variable peak pricing, critical peak pricing, and critical peak rebate programs. *See* EIA, *Form EIA-861S Annual Electric Power Industry Report (Short Form) Instructions* at 3-4, https://www.eia.gov/survey/form/eia_861s/instructions.pdf; and EIA, *Form EIA-861 Annual Electric Power Industry Report Instructions,* Schedule 6 Part C, https://www.eia.gov/survey/form/eia_861/instructions.pdf.

[58] For the benefit of the reader, previous years' Assessments of Demand Response and Advanced Metering contain similar reporting of federal, regional, state, and industry activities.

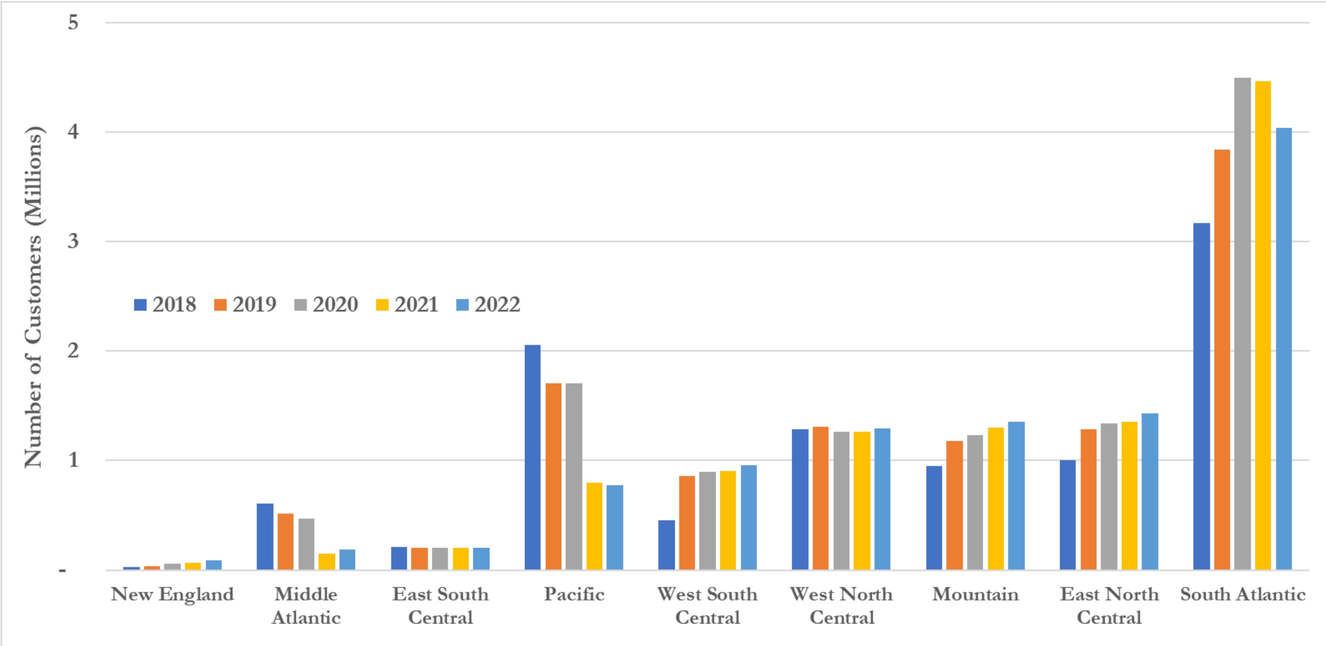
Table 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2021 and 2022)

Census Division	Enrollment in Retail Demand Response Programs		Year-over-Year Change	
	2021	2022	Customers	%
East North Central	1,356,961	1,431,542	74,581	5.5%
East South Central	199,657	203,712	4,055	2.0%
Middle Atlantic	146,662	184,804	38,142	26.0%
Mountain	1,302,405	1,356,157	53,752	4.1%
New England	63,140	86,732	23,592	37.4%
Pacific	793,563	773,107	-20,456	-2.6%
South Atlantic	4,465,363	4,034,799	-430,564	-9.6%
West North Central	1,260,090	1,295,155	35,065	2.8%
West South Central	904,743	953,766	49,023	5.4%
Total	**10,492,584**	**10,319,774**	**-172,810**	**-1.6%**

Sources: 2022 Form EIA-861 Utility_Data_2022 data file, 2022 Form EIA-861 Demand_Response_2022 data file, 2021 Form EIA-861 Utility_Data_2021 data file, and 2021 Form EIA-861 Demand_Response_2021 data file.
Notes: 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. Values from source data are rounded for publication.

Figure 5-1 below shows changes in customer enrollment in retail incentive-based demand response programs in each Census Division from 2018 to 2022. Over this period, the trends in customer enrollment in such programs varied across Census Divisions. From 2021 to 2022, utilities in seven of the nine Census Divisions experienced increases in customer enrollment in retail incentive-based demand response programs. In aggregate, utilities in the East North Central Census Division reported approximately 75,000 additional customers, or 5.5% increase, enrolled in retail incentive-based demand response programs in 2022, the largest increase among Census Divisions. Utilities in the East North Central Census Division with notable increases include Consumer Energy Co. in Michigan and Commonwealth Edison Co. in Illinois which reported approximately 59,000 and 33,000 additional customers enrolled, respectively. The New England Census Division experienced the largest percent increase in customer enrollment in retail incentive-based demand response programs with utilities reporting approximately 24,000 more customers, or 37.4% increase, in 2022. NSTAR Electric Co. in Massachusetts and Connecticut Light & Power Co. saw the largest increases in the Census Division, reporting approximately 10,000 and 5,000 more customers enrolled in 2022 compared to 2021, respectively. Utilities in other Census Divisions also experienced significant increases in enrollment in retail demand response programs. Those reporting increases include Arizona Public Service Co. in the Mountain Census Division (23,000 additional customers enrolled), Oklahoma Gas & Electric Co. in Oklahoma in the West South Central Census Division (19,000), and Evergy Metro in Missouri in the West North Central Census Division (14,000).

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2018 – 2022)



Sources: EIA-861 Demand Response data files 2018 – 2022.

As discussed above, the Pacific and South Atlantic Census Divisions experienced decreases in customer enrollment, with utilities in those Census Divisions reporting approximately 20,000 and 431,000 fewer customers enrolled in 2022 compared to 2021, respectively. The largest decreases were reported by Potomac Electric Power Co. in Maryland (202,000 fewer customers enrolled), Delmarva Power in Delaware (37,000), and Delmarva Power, Maryland (34,000). The decrease in the Pacific Census Division was mainly due to utilities in California reporting in aggregate approximately 26,000 fewer customers enrolled in retail incentive-based demand response programs.

Turning to retail dynamic pricing programs, Table 5-2 below illustrates customer enrollment in retail dynamic pricing programs for each of the nine Census Divisions in 2021 and 2022. From 2021 to 2022, customer enrollment in retail dynamic pricing programs in the United States increased by approximately 954,000 customers, or 6.5%. Five Census Divisions experienced aggregate increases in customer enrollment. The West North Central Division experienced the largest aggregate increase, with utilities reporting approximately 567,000 additional customers enrolled in retail dynamic pricing programs in 2022. The significant annual enrollment increase in the West North Central Division resulted from a large rise in customers enrolled in Missouri, mostly from the Union Electric Co. and the Empire District Electric Co. utilities. Utilities in the East North Central, Middle Atlantic, Mountain, and Pacific Census Divisions also reported more customers enrolled in retail dynamic pricing programs in 2022 compared to 2021. While overall enrollment in retail dynamic pricing programs increased nationwide, the East South Central, New England, South Atlantic, and West South Central Census Divisions experienced aggregate decreases in customer enrollment. Utilities in the West South Central Census Division reported approximately 528,000 fewer customers enrolled in retail dynamic pricing programs in 2022, which represented the largest decrease among Census Divisions.

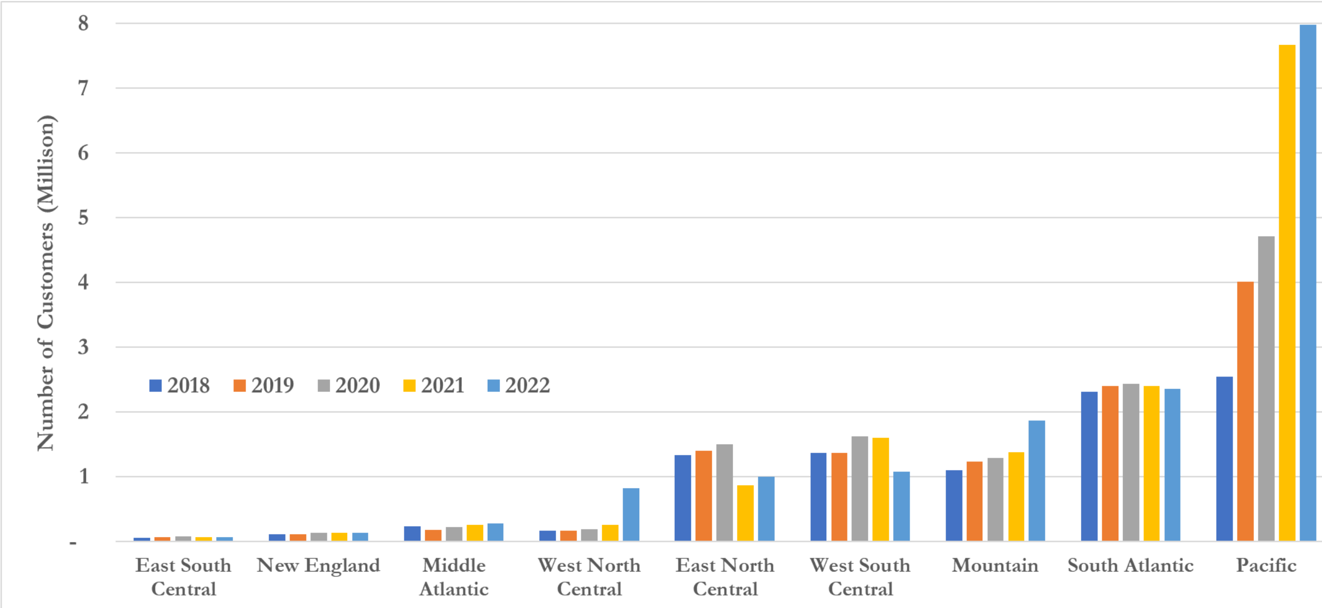
Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2021 and 2022)

Census Division	Enrollment in Dynamic Pricing Programs		Year-over-Year Change	
	2021	2022	Customers	%
East North Central	863,185	997,574	134,389	15.6%
East South Central	72,446	69,859	-2,587	-3.6%
Middle Atlantic	259,426	276,014	16,588	6.4%
Mountain	1,377,686	1,868,528	490,842	35.6%
New England	138,943	136,319	-2,624	-1.9%
Pacific	7,665,830	7,983,495	317,665	4.1%
South Atlantic	2,397,528	2,357,868	-39,660	-1.7%
West North Central	261,577	828,644	567,067	216.8%
West South Central	1,606,630	1,078,678	-527,952	-32.9%
Total	**14,643,251**	**15,596,979**	**953,728**	**6.5%**

Source: 2022 Form EIA-861 Dynamic_Pricing_2022 data file, 2022 Form EIA-861 Utility_Data_2022 data file, 2021 Form EIA-861 Dynamic_Pricing_2021 data file, and 2021 Form EIA-861 Utility_Data_2021 data file.
Note: Although some utilities may operate in more than one state and Census Division, EIA data are reported by utility at the state level. Commission staff has not independently verified the accuracy of EIA data. Values from source data are rounded for publication.

Figure 5-2 below shows customer enrollment in retail dynamic pricing programs in each Census Divisions from 2018 through 2022. Over this period, customer enrollment in retail dynamic pricing programs showed an upward trend across all Census Divisions except for the East North Central and West South Central. Utilities in the Pacific Census Division continued to report the largest aggregate number of customers enrolled in retail dynamic pricing programs, with approximately 8.0 million customers enrolled in 2022. Notably, Southern California Edison reported approximately 1.6 million more customers enrolled in retail dynamic pricing programs in 2022 compared to 2021. Utilities in other Census Divisions also experienced significant increases in customer enrollment from 2021 to 2022. For example, Public Service Co of Colorado in the Mountain Census Division reported 486,000 additional customers enrolled in retail dynamic pricing programs in 2022, while Union Electric Co. and Empire District Electric Co. in the West North Central Census Division reported 390,000 and 158,000 additional customers enrolled, respectively. While the Pacific Census Division reported the largest aggregate number of customers enrolled, the West North Central and Mountain Census Divisions both had higher year-over-year increases from 2021 to 2022, with approximately 567,000 and 491,000 more customers enrolled in retail dynamic pricing programs, respectively.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 – 2022)



Sources: EIA-861 Dynamic Pricing data files 2018 – 2022.

FERC Demand Response Orders and Activities

NYISO DER Aggregation (ER23-2040)

As explained in last year's report, NYISO filed proposed tariff revisions in June 2023 to modify its DER and Aggregation participation model that the Commission first accepted in January 2020.[59] As part of this filing, NYISO proposed to implement a previously approved phaseout of its existing economic-based demand response programs and a 12-month transition period for resources participating in those programs to switch to the DER and Aggregation participation model. On April 15, 2024, the Commission accepted NYISO's proposal.[60] The Commission found that NYISO's proposed transition of existing Special Case Resources and Generators to DERs participating in an Aggregation would streamline resource transition to the new participation model while ensuring that the capacity that an Aggregator can claim for those Resources is restricted to its demonstrated capacity.[61]

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[59] FERC, *Annual Assessment of Demand Response and Advanced Metering* at 29 (Nov. 2023), https://cms.ferc.gov/media/2023-assessment-demand-response-and-advanced-metering.

[60] *NYISO*, 187 FERC ¶ 61,022, at P 1 (2024).

[61] *Id.* at P 30.

SPP Order No. 2222 Compliance Filing (ER22-1697)

On April 28, 2022, SPP submitted proposed tariff revisions to the Commission to comply with the requirements of Order No. 2222.[62] On March 1, 2024, the Commission accepted SPP's compliance filing subject to a further compliance filing.[63] As relevant to demand response, the Commission found that SPP partially complied with Order No. 2222's demand response opt-out requirements because certain proposed tariff revisions improperly applied the opt-out requirements of Order No. 719 to demand response participating in DER aggregations.[64] The Commission also found that SPP only partially complied with the participation eligibility requirements of Order No. 2222, determining that SPP's proposal did not accommodate the physical and operational characteristics of heterogeneous DER aggregations that can provide energy injection and demand response, as required.[65] In addition, the Commission directed SPP to revise its tariff to apply the requirements of Order No. 745 to demand response resources participating in heterogeneous aggregations.[66] Finally, the Commission directed SPP to clarify the meter data submission deadline and how its existing process for reporting telemetered changes in demand response load would apply to certain heterogeneous DER aggregations.[67] On July 11, 2024 the Commission granted a motion by SPP for an extension of time to December 26, 2024 to submit its compliance filing.[68]

Commission Enforcement Activity

On January 4, 2024, the Commission issued an order approving a Stipulation and Consent Agreement that resolved the Commission's Office of Enforcement's investigation of a demand response resource participant, Linde Inc. (Linde), and its Market Participant, Northern Indiana Public Service Company LLC (NIPSCO), and whether they violated MISO's Tariff or Commission regulations.[69] NIPSCO is a load-serving entity that processed Linde's demand response offers to MISO and payments from MISO as Linde's Market Participant.[70] In the Stipulation and Consent Agreement, Linde agreed to: (1) disgorge $48,500,000 it received through its participation as a DRR-1 unit in MISO during the Relevant Period; (2) pay a civil penalty of $10,500,000 to the United States Treasury; and (3) provide compliance training to all personnel

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[62] Sw. Power Pool, Inc., Filing, Docket No. ER22-1697-000 (filed Apr. 28, 2022).

[63] *Sw. Power Pool, Inc.,* 186 FERC ¶ 61,162, at P 1 (2024)

[64] *Id.* at P 48

[65] *Id.* at P 104

[66] *Id.* at P 123-125.

[67] *Id.* at P 286.

[68] Sw. Power Pool, Inc., Formal Notice, Docket No. ER22-1697-000 (issued July 11, 2024).

[69] *Linde Inc. and Northern Indiana Public Service Company LLC*, 186 FERC ¶ 61,009, at P 1.

[70] *Id.* at P 9.

involved if it intends to participate again as a DRR-1 asset in MISO.[71] In addition, NIPSCO agreed to: (1) disgorge $7,700,000 it received in connection with Linde's participation as a DRR-1 asset in MISO, and (2) make an appropriate filing with the Indiana Utility Regulatory Commission to ensure that NIPSCO customers receive a refund equivalent to the amount they were charged because of Linde's participation as a DRR-1 asset in MISO during the Relevant Period.[72]

Other Federal Demand Response Activities

Department of Defense

The U.S. Department of Defense (DOD) Defense Logistics Agency Energy (DLA Energy) provides DOD and other federal agencies with a variety of commodities procurement services and energy solutions.[73] DLA Energy's Installation Energy Division provides acquisition support for facility energy commodities and services, and also serves as coordinator and facilitator for the DOD's participation in demand response programs.[74] In fiscal year 2023, DLA Energy facilitated the participation of 32 federal installations across seven states and the District of Columbia in demand response programs.[75] This participation collectively represents approximately 139 MW of enrolled resources and resulted in approximately $4.6 million in savings in fiscal year 2023.

Developments and Issues in Demand Response

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

California. On October 18, 2023, the California Energy Commission (CEC) adopted and issued flexible demand appliance standards for swimming pool controls.[76] Starting in September 2025, pool controls in California will need to be connected devices with a default operating schedule capable of receiving and responding to authorized remote requests that schedule, shift, or curtail appliance operations with customer

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[71] *Id.* at P 2.

[72] *Id.* at P 3.

[73] Defense Logistics Agency Energy, *Fiscal Year 2023 Fact Book* at 6, https://www.dla.mil/Portals/104/Documents/Energy/Publications/DLAEnergyFactBook2023_final_hyperlinked_2.pdf?ver=V60WCASoAoI0M7smH1qJ6g%3d%3d.

[74] *Id.* at 16.

[75] *Id.* at 56.

[76] California Energy Commission, Flexible Demand Appliance Standards for Pool Controls at 4 (Oct. 18, 2023), https://efiling.energy.ca.gov/GetDocument.aspx?tn=252658&DocumentContentId=87732.

or consumer consent, along with many other standards including cybersecurity requirements.[77] The CEC estimated that a total of 64 GWh of electricity will shift off peak during the first year the regulation is in effect and shift 682 GWh of electricity per year once when all pool controls in the state are replaced.[78]

On April 18, 2024, the California PUC issued a final decision determining that the Demand Response Auction Mechanism (DRAM) pilot programs will sunset by December 31, 2024.[79] The DRAM, established in December 2014 and conducted from 2016 through 2024, is a pay-as-bid solicitation in which investor-owned utilities procure demand response resources from third-party Demand Response Providers (DRPs) that bid these resources directly into the CAISO energy markets.[80] The DRAM pilot programs intended to test the feasibility of a competitive market for procuring supply-side demand response resources.[81] The California PUC commissioned a report to evaluate whether the DRAM pilot was successful.[82] Specifically, the report assessed whether the DRAM engaged new DRPs and customers, whether auction bid prices and offer prices were competitive, whether DRPs met their contractual obligations, and whether resources were reliable when dispatched. The report found the DRAM did not meet all the evaluation criteria, particularly in the areas of performance and reliability.[83] As a result, the California PUC decided to sunset the DRAM pilot program concluding that it failed to demonstrate reliability and cost-competitiveness.[84]

Colorado. On February 7, 2024, the Colorado Public Service Commission (Colorado Commission) issued an order in a Public Service Company of Colorado (Public Service Colorado) rate case that modified the utility's proposed time of use (TOU) rates.[85] The settling parties to an earlier Public Service Colorado rate case had agreed that the time periods of the TOU rates would not change until 2025, when Public Service Colorado would initiate the change. However, in this proceeding, Public Service Colorado submitted testimony stating that an analysis of load net of renewable generation output for the highest 100 hours of each year from 2024 through 2030 demonstrates that shifting the on-peak pricing periods to later in the day would be appropriate in the future, and that higher demand may occur during winter morning hours due to

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[77] *Id.*

[78] California Energy Commission, *Analysis of Flexible Demand Standards for Pool Controls* (February 2023) at 64, https://efiling.energy.ca.gov/GetDocument.aspx?tn=248922.

[79] *Decision Sunsetting the Investor-Owned Utilities' Demand Response Auction Mechanism Pilot Programs*, Decision 24-04-006 at 2 (California PUC Apr. 24, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M530/K195/530195415.PDF.

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

[81] *Id.* at 2.

[82] Id. at 9.

[83] Id. at 22.

[84] *Id.* at 29.

[85] *Commission Decision Permanently Suspending Tariff Sheets and Establishing Rates*, Docket No. C24-0117 (Colorado Public Utility Commission Feb. 7, 2024).

increasing electrification. The Colorado Commission concluded that changes to the TOU rate should commence before the beginning of the 2025 summer cooling season because drivers other than peak summer hours have begun to dictate system costs.[86]

On April 5, 2024, the Colorado Commission issued a decision, with modifications and clarifications, adopting a recommended decision that supported the development and implementation of a natural gas demand response pilot program targeted on areas of natural gas capacity constraint, as well as the development and implementation of pilot programs for VPPs and neighborhood electrification.[87] The VPP pilot program intends to accomplish various objectives, including facilitating the delivery of demand response, enhancing the customer experience, shaping load, managing distribution system load, and achieving operational savings and efficiency.[88] In addition, the natural gas demand response pilot program is intended to avoid costly investments in gas infrastructure and to shift natural gas consumption to off-peak times.[89]

Maine. On November 20, 2023, the Maine Public Utilities Commission (Maine PUC) issued a report on the implementation of TOU rates, pursuant to a directive by the Maine legislature.[90] The report focused on the feasibility of implementing TOU rates, specifically the feasibility of requiring standard service to include a TOU rate option, and whether the Maine PUC should recommend a pilot program of this type as appropriate. The report also addressed the question of whether all Maine investor-owned transmission and distribution utilities should offer a TOU delivery rate that would complement a TOU supply rate.[91] The Maine PUC found that a carefully designed TOU rate for supply and distribution rates may shift load, reduce peak peaks, and therefore reduce overall cost to rate payers.[92] The Maine PUC determined that a pilot program is not necessary because it would not allow sufficient enrollment to realize meaningful reductions in peak load or deferred capital investment, and therefore would not enable the Maine PUC to assess the full benefits of a TOU rate. The Maine PUC also found that it could rely on work conducted by

[86] *Id.*

[87] *Commission Decision Granting, In Part, and Denying, In Part, Exceptions to Recommended Decision No. R24-0009 and Closing Proceeding*, Decision No. C24-021,1 at 1 and 4 (Colorado PUC Apr. 5, 2024), https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=23M-0466EG.

[88] *Recommended Decision Of Hearing Commissioner Tom Plant Issuing Certain Guidance For Requests For Proposals To Be Issued By Public Service Company Of Colorado,* Decision No. R24-0009, at 13 (Colorado PUC Jan. 5, 2024), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1013626.

[89] *Id.* at 21-22.

[90] Maine Public Utility Commission, *Report Regarding the Implementation of Time-of-Use Rates Pursuant to Resolves 2023, chapter 79* (Nov. 20, 2023), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId=%7bD0DE348F-0000-C619-A3CF-D42260542D24%7d&DocExt=pdf&DocName=%7bD0DE348F-0000-C619-A3CF-D42260542D24%7d.pdf.

[91] *Id.* at 1.

[92] *Id.* at 3.

other states and that for a TOU rate to be successful it needs to be an opt-out program. The report also states that the Maine PUC plans to open a formal investigation into the adoption of a TOU supply rate.[93]

Minnesota. On December 22, 2023, Northern States Power Company, a subsidiary of Xcel Energy, submitted a petition for a residential TOU rate design.[94] Northern States Power Company is proposing to implement this TOU rate design for all residential customers in its territory.[95] The proposal builds upon a pilot program that ran from 2020 to 2022 and is designed to reduce peak demand and provide an opportunity for customers to save money on their electricity bill by shifting when they consume electricity.[96] The TOU would have three period energy charges (Peak, Off-Peak, and Base).[97]

Wisconsin. On May 31, 2024, the Court of Appeals of Wisconsin issued a decision in *Midwest Renewable Association v. Public Service Commission of Wisconsin* that held invalid and unenforceable a temporary prohibition of the operation of third party aggregators of retail customers issued by the Public Service Commission of Wisconsin. The Wisconsin Court of Appeals held that the prohibition was not proposed and promulgated in compliance with Wisconsin's rulemaking requirements.[98]

Wyoming. On July 8, 2024, Rocky Mountain Power filed with the Wyoming Public Service Commission a request for an order approving its new Commercial and Industrial Demand Response (C&I DR) Pilot Program.[99] Rocky Mountain Power states that the C&I DR Pilot Program will serve participating large commercial and industrial customers in Wyoming with curtailable loads greater than 500 kW and provide them with financial incentives to curtail loads during curtailment events.[100] If approved, Rocky Mountain

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[93] *Id.*

[94] *Petition of Xcel, Residential Time of Use Rate Design*, E002/M-23-524, at 1 (Minn. Public Utilities Commission Dec. 22, 2023), https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b6069A68C-0000-C314-B0C2-0ADC84D62B9B%7d&documentTitle=202312-201532-01.

[95] *Id.*

[96] *Id.*

[97] *Id.* at 11.

[98] *Midwest Renewable Energy Ass'n v. Pub. Serv. Comm'n of Wis.*, 8 N.W.3d 848, 866-877 (Wis. Ct. App. 2024), https://www.wicourts.gov/ca/opinion/DisplayDocument.pdf?content=pdf&seqNo=808038.

[99] *In the Matter of the Application of Rocky Mountain Power for Approval of a Five-Year Commercial and Industrial Demand Response Pilot Program and Recovery Mechanism Exhibit 1.0*, Docket No. 20000-670-ET-24, Record No. 17625, at 1-2 (Wyoming PSC July 08, 2024), https://dms.wyo.gov/OpenAttachment.aspx?file=hdaniels_17625_070920241044.09AM_Application%20for%20CI%20DR%20Program.pdf.

[100] *Id.* at 4.

Power argues that the C&I DR Pilot Program is forecasted to reach 53.3 MW of cumulative curtailable demand response load from 2025 to 2029 at an estimated total cost of $20.1 million.[101]

Collaborative Industry-Government Efforts

Department of Energy. As discussed in Chapter 2, several GRIP Program projects were selected to receive Smart Grid Grants incorporate the deployment of AMI technology.[102] In addition to the deployment of AMI technology already discussed, several of the GRIP Program projects selected to receive Smart Grid Grants will facilitate the integration of DERs into distribution grid systems. For example, through its Community Grid Innovation Program, the Los Angeles Department of Water and Power plans to deploy and enroll 7,500 smart thermostats, totaling 5 MW of DER capacity.[103] It will use a DERMS platform to provide grid operators with visibility of DERs on the electrical system and the ability to dispatch these units to maintain grid reliability. Another grant recipient, the American Electric Power Service Corporation, plans to implement an advanced distribution management system (ADMS) coupled with a DERMS platform to increase its grid visibility and distribution management capabilities of DERs.[104] It anticipates that the proposed work will improve grid reliability by approximately 5% and avoid reliability related productivity losses worth $1.9 billion over 20 years. Similarly, National Grid USA Service Company plans to deploy technology solutions in upstate New York and Massachusetts to maximize the value of DERs by enhancing DER operational flexibility for critical load balancing functions.[105]

North American Energy Standards Board. On February 5, 2024, the North American Energy Standards Board (NAESB) announced that it will work with DOE to develop a standardized contract to facilitate the

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

[102] DOE, *Biden-Harris Administration Announces $3.5 Billion for Largest Ever Investment in America's Electric Grid, Deploying More Clean Energy, Lowering Costs, and Creating Union Jobs* (Oct. 2023), https://www.energy.gov/articles/biden-harris-administration-announces-35-billion-largest-ever-investment-americas-electric.

[103] DOE Grid Deployment Office, *GRIP Program Fact Sheet: Supporting Distribution During Grid Stress,* https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2081_Los%20Angeles%20Department%20of%20Water%20and%20Power_v4_RELEASE_508.pdf.

[104] DOE Grid Deployment Office, *GRIP Program Fact Sheet: Increasing Grid Visibility Across the American East and Midwest,* https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2044_American%20Electric%20Power%20Service%20Corporation_v4_RELEASE_508.pdf.

[105] DOE Grid Deployment Office, *GRIP Program Fact Sheet: The Future Grid Project,* https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_2115_National%20Grid%20USA%20Service%20Company%2C%20Inc_v4_RELEASE_508.pdf.

provision of distribution grid services from DER aggregations.[106] DOE submitted the request in support of its Distribution Grid Transformation Program, which works with the electric industry to proactively address grid transformation issues. In the request, DOE states that the lack of a standard contract that specifies the performance expectations from aggregators is a significant market barrier inhibiting DERs from providing distribution grid services. The goal is to develop a standard contract, through a consensus-based process, that aligns with state policies while providing flexibility for regulators and trading partners. The contract will create consistency in terms and definitions, minimize uncertainties, and reduce costs associated with negotiations. The DOE's request states that this will encourage operational coordination across distribution and wholesale interactions and enable seamless participation for DER aggregations seeking to participate in wholesale markets, consistent with FERC Order No. 2222. NAESB states that its open process will allow participation from any interested stakeholder, thereby facilitating cross-market considerations.

On September 12, 2024, NAESB released for industry-wide comment the Base Contract for the Sale and Purchase of Distribution Services (NAESB Distribution Services Contract).[107] NAESB states that its Distribution Service Contract establishes boilerplate terms and conditions that will reduce uncertainties in contracting terms and reduce costs associated with counterparty negotiations. At the suggestion of participants in the drafting process, an addendum to the contact, the NAESB Conditions Precedent Addendum, was added. NAESB states that the optional addendum allows DER aggregators and distribution utilities to specify regulatory, testing, certification, or other requirements and milestones that must be met before the DER aggregator completes the registration process with the utility and executes transactions under the NAESB Distribution Services Contract. The comment period ended on October 7, 2024. A final vote on the recommended contract is pending.

[106] NAESB, *NAESB to Work with U.S. Department of Energy to Develop Standard Distribution Services Contract* (Feb. 2024), http://www.naesb.org/pdf4/020524press_release.pdf.

[107] NAESB, *NAESB Releases Standard Distribution Services Contract for Industry-Wide Comment Period* (Sep. 2024), https://www.naesb.org/pdf4/091224press_release.pdf.

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

Utilities and regulators continue to evaluate demand response, peak reduction, and critical peak pricing programs to determine how best to leverage new types of flexible loads to cost effectively meet power system needs and accommodate changes in the resource mix and demand. The data in Chapter 5 suggests that utilities are focusing on increasing enrollment in dynamic pricing programs that leverage their advanced meter investments. However, customer enrollment in demand response programs in some regions has slowed in recent years. The growing penetration of customer-sited DERs presents grid operators with new opportunities to leverage aggregations of these devices to provide grid-scale services—such as demand response and peak reduction. This section discusses barriers that may be limiting customer participation, and efforts to address those barriers.

Integrating DERs and Dynamic Pricing in System Planning

For utilities to maximize the benefits that DER aggregations, VPPs, dynamic pricing programs, or price-based demand response can provide, it would be beneficial for DERs and dynamic pricing programs to be fully integrated into utility system planning. However, integrating these resources into system planning remains challenging. In its *VPP Liftoff Report*, DOE notes that while awareness of DERs is common, familiarity with VPPs is low nationally among utility regulators, leading to skepticism about VPP performance.[108] Additionally, existing methods for valuing DERs and VPPs are not comprehensive, which DOE has determined results in underestimated VPP benefits and under-compensation of VPP participants. The complexity of aligning multiple state utility planning requirements with compensation frameworks further adds to the difficulty of ensuring system-optimal VPP deployment. Moreover, some state commissions may have limited resources and personnel to fully assess the regulatory changes needed to integrate VPPs. To overcome these challenges, the *VPP Liftoff Report* suggests the following: (1) advanced modeling and decision tools can be developed to comprehensively evaluate VPP benefits, improve cost-benefit assessments, and inform state and local policy decisions; (2) integrated distribution system planning requirements, supported by increased technical assistance and visibility into grid constraints, can better align utility planning with long-term forecasts and state goals; (3) aligning utility incentives and rate design with system-optimal resources, including performance-based payments and advanced rate structures, can drive more effective VPP deployment; and (5) proactive utility leadership in VPP planning, including setting clear objectives and optimizing customer incentives, can further support effective integration and grid management.[109]

With regard to price-based demand response, a recent Lawrence Berkley National Laboratory (LBNL) report finds that such programs can substantially contribute to load flexibility but are an underutilized

[108] *VPP Liftoff Report* at 48-49.

[109] *Id*. at 49-51.

resource.[110] LBNL analyzed a sample of integrated resource plans (IRPs) and distribution system plans to understand how price-based demand response is treated as a solution to system needs. The study found that, where price-based demand response is considered as a solution, methodologies are often deficient, for example inconsistent or lacking transparency. Despite detailed evaluations of price-based demand response, utilities frequently screen out, combine, or omit these resources in their preferred portfolios.[111] This results in a lack of clarity regarding the type of and rationale for the level of demand response that was adopted. Additionally, utilities may treat demand response as load reductions rather than as a resource on par with other resource options, which means that its cost effectiveness cannot be directly compared against other resources and may result in under-procurement of demand response. Other deficiencies LBNL found in IRP analyses include lack of transparency in demand response supply curves, and low capacity values assigned to demand response. LBNL also found that price-based demand response is typically not included in utility distribution system plans outside of load forecasting, pilots, or non-wire alternatives.[112]

Access to Grid Data to Facilitate DER Deployment

DER developers require access to power system information that utilities use for grid planning and operation (grid data) to make informed decisions regarding siting and programming to ensure optimal deployment of their investments. However, grid data is commonly held within the utility and access can be limited. In November 2023, the National Association of Regulatory Utility Commissioners (NARUC) released a brief summarizing current state practices for grid data sharing.[113] In the report, NARUC notes that public utility commissions are increasingly requested to resolve questions related to third-party access to grid data that utilities use to plan and operate the electric system.[114] NARUC found that data sharing practices vary by state and utility, with 14 states having considered whether and how utilities should make hosting capacity[115] data available publicly or to DER developers. NARUC also found that at least 35 utilities publish some type of hosting capacity information. Few state regulators, utilities, and stakeholders engaged in comprehensive consideration of grid data sharing, according to the brief. NARUC's Grid Data Sharing Collaborative developed a framework to assist state public utility commissions and their stakeholders with

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[110] LBNL, *The Use of Price-based Demand Response as a Resource in Electricity System Planning* at 1 (Nov. 2023), https://live-etabiblio.pantheonsite.io/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf.

[111] *Id.* at 15.

[112] *Id.* at 21.

[113] NARUC, *Grid Data Sharing: Brief Summary of Current State Practices* (Nov. 2023), https://pubs.naruc.org/pub/145ECC5C-1866-DAAC-99FB-A33438978E95?_gl=1*1fh9u8n*_ga*MTE4NTA2NDA2My4xNzA1OTM3NTg2*_ga_QLH1N3Q1NF*MTcyMzQ4NDkxMS44LjEuMTcyMzQ4NTE2MC4wLjAuMA..

[114] NARUC notes that their focus is on data related to the power system, up to and including the electric meter and not on customer data behind the meter. *Id.* at 1 n. 1.

[115] Hosting capacity analysis is used to establish a baseline for the maximum amount of DERs that a distribution system can accommodate reliably without upgrades. *Id.* at 3.

balancing these issues. Released in November 2023, the framework is composed of a series of questions grouped under seven categories that facilitate the collection, examination, and documentation of inputs to inform grid data sharing decisions.[116] The categories include use cases; state priorities; current practices, requests for additional data, and options for enabling use-cases; data details; potential impacts; and data sharing tactics. NARUC also released a Grid Data Sharing Playbook and Factsheet that provide detailed explanations, with examples, of the framework and serve as a guide to help with implementation.

As mentioned above, some states are taking a comprehensive approach to addressing grid data sharing challenges. For example, on March 28, 2024 the New York State Energy Research and Development Authority (NYSERDA) announced the completion of the first phase of the New York State Integrated Energy Data Resource platform, which aims to centralize and expand access to energy-related data, including grid data, from New York electric, gas, and steam utilities to foster innovation and accelerate clean energy deployment.[117] The first phase provides user access to features such as utility hosting capacity maps, DER siting data, and tools for rate and tariff information. A sandbox environment for testing customer billing data features was also launched. The second phase will broaden the platform's scope to include additional data on energy consumption and emissions. Nearby, a group of New England utilities is seeking to do something similar across four states.[118] Unitil, Eversource, and Liberty Utilities, along with other stakeholders, applied for DOE GRIP Program funding to develop a regional energy data platform aimed at improving access to detailed energy usage. The project will build on a similar initiative launched in New Hampshire and will provide standardized access to energy usage information for utility customers and third-party service providers in New Hampshire, Connecticut, Maine, and Massachusetts.

Implementing Demand Management Techniques for EV Load Growth

In January 2024, the Energy Systems Integration Group (ESIG) published a report on grid planning for vehicle electrification, including how planners can prepare the system for EV growth by determining where

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[116] NARUC, *Grid Data Sharing Framework Factsheet* (Nov. 2023), https://pubs.naruc.org/pub/7411B065-B9E5-DE03-4CA4-1F875B0A0416?_gl=1*1s1e3e9*_ga*MTE4NTA2NDA2My4xNzA1OTM3NTg2*_ga_QLH1N3Q1NF*MTcyMzQ4NDkxMS44LjEuMTcyMzQ4NTE2MC4wLjAuMA. *See also,* NARUC, *Grid Data Sharing Playbook* (Nov. 2023), https://pubs.naruc.org/pub/E2E50FD7-CD1B-62D5-1071-8D8362AD1E6D?_gl=1*1s1e3e9*_ga*MTE4NTA2NDA2My4xNzA1OTM3NTg2*_ga_QLH1N3Q1NF*MTcyMzQ4NDkxMS44LjEuMTcyMzQ4NTE2MC4wLjAuMA.

[117] NYSERDA, *First Development Phase Of The New York State Integrated Energy Data Resource Platform Completed* (Mar. 2024), https://www.nyserda.ny.gov/About/Newsroom/2024-Announcements/2024_03_28-NYSERDA-Announces-Completion-of-First-Development-Phase-of-the-NYS-IEDR-Platform#:~:text=Today's%20announcement%20signals%20the%20completion,)%2C%20which%20is%20now%20live.

[118] New Hampshire Bulletin, *New England Utilities Plan Data Platform to Make It Easier to Calculate Energy Savings* (May 2024), https://newhampshirebulletin.com/2024/05/09/new-england-utilities-plan-data-platform-to-make-it-easier-to-calculate-energy-savings/.

to make grid upgrades and evaluating smart charging solutions.[119] The study found that while the electrification of transportation will affect all aspects of the electric system, it will have a more pronounced effect on the distribution system.[120] The report found that transportation electrification is accelerating because of consumer demand, vehicle manufacturer commitment, and public policies. However, the report found that the grid infrastructure needed to support this growth in transport electrification has lagged, and this leads to less time to plan and build the needed grid upgrades.[121] The report found that demand management techniques, such as TOU rates, to mitigate the need for grid upgrades, could be important tools in managing the charging of EVs.[122] The study found that while demand management techniques will not be able to mitigate all the needs for EV-related infrastructure investment, they can alleviate the stress from unmanaged charging and help manage conflicting grid needs.[123] The report identified several challenges to demand management techniques that included customer participation, preserving load diversity, implementing communication and control standards, pricing sensitivity and its effects on reliability, and the modeling of smart charging.[124]

[119] Energy Systems Integration Group, *Charging Ahead: Grid Planning for Vehicle Electrification* at 1 (Jan. 2024), https://www.esig.energy/wp-content/uploads/2024/01/ESIG-Grid-Planning-Vehicle-Electrification-report-2024.pdf. The Energy Systems Integration Group (ESIG) is a non-profit educational organization that provides resources for the energy sector.

[120] *Id.*

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

[122] *Id.* at 29.

[123] *Id.* at 30.

[124] *Id.* at 40-40

Appendix I: List and Map of Census Divisions

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

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

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

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

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

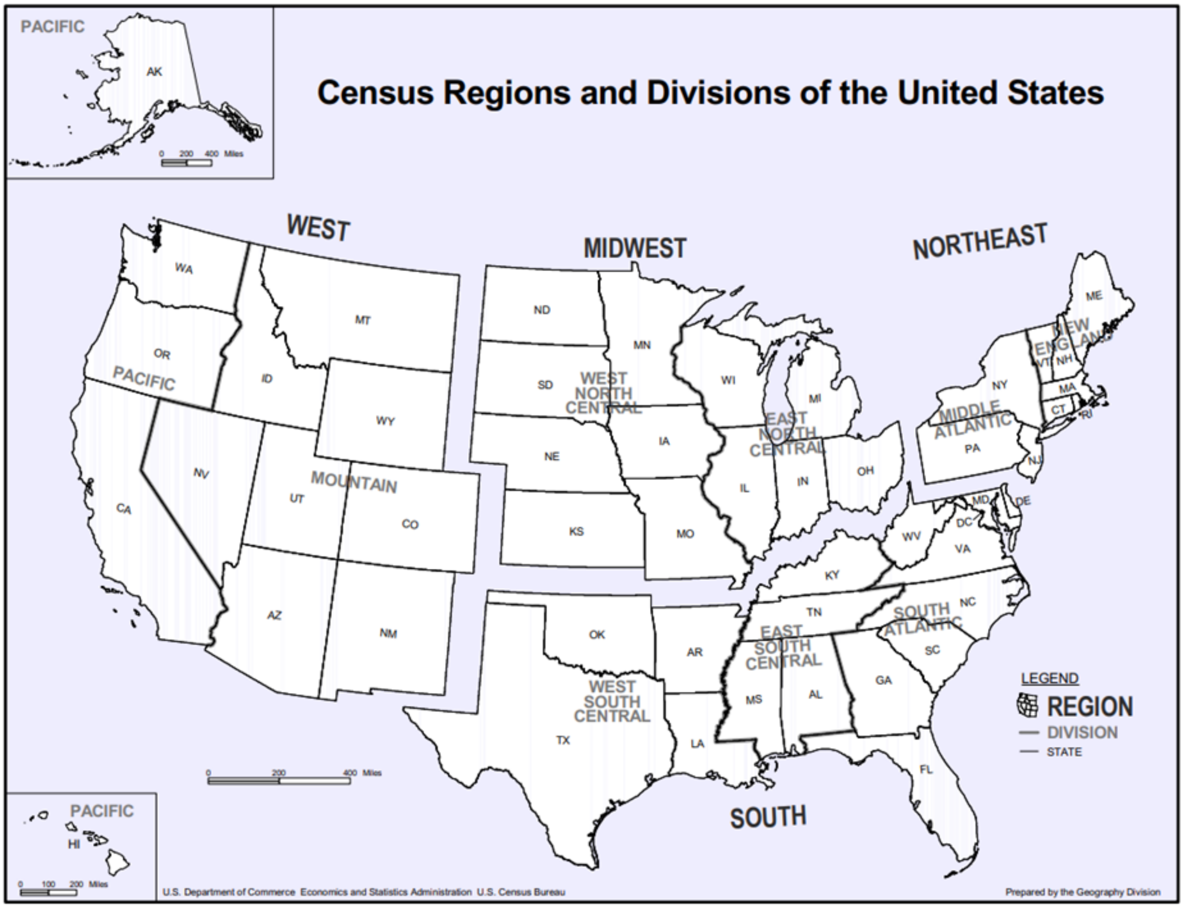
Division 5, South Atlantic: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia

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

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

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

Division 9, Pacific: Alaska, California, Hawaii, Oregon, Washington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U.S. Department of Commerce Economics and Statistics Administration U.S. Census Bureau
Prepared by the Geography Division

Appendix II: Estimates of Advanced Meter Penetration Rates in the United States (2007 – 2022)

Data Source	Data as Of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2008 FERC Survey[1]	Dec 2007 (FERC)	6.7	144.4	4.7%
2010 FERC Survey[1]	Dec 2009 (FERC)	12.8	147.8	8.7%
2012 FERC Survey[1]	Dec 2011 (FERC)	38.1	166.5	22.9%
2011 Form EIA-861[2]	Dec 2011 (EIA)	37.3	144.5	25.8%
2012 Form EIA-861[2]	Dec 2012 (EIA)	43.2	145.3	29.7%
2013 Form EIA-861[2]	Dec 2013 (EIA)	51.9	138.1	37.6%
2014 Form EIA-861[2]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[2]	Dec 2015 (EIA)	64.7	150.8	42.9%
2016 Form EIA-861[2]	Dec 2016 (EIA)	70.8	151.3	46.8%
2017 Form EIA-861[2]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[2]	Dec 2018 (EIA)	86.8	154.1	56.4%
2019 Form EIA-861[2]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[3]	Dec 2019 (IEI)	99.0	157.2	63.0%
2020 Form EIA-861[2]	Dec 2020 (EIA)	103.1	159.7	64.6%
Institute for Electric Innovation[3]	Dec 2020 (IEI)	107.4	159.7	67.2%
2021 Form EIA-861[2]	Dec 2021 (EIA)	111.2	162.8	68.3%
Institute for Electric Innovation[3]	Dec 2021 (IEI)	115.3	162.8	70.8%
2022 Form EIA-861[2]	Dec 2022 (EIA)	119.3	165.0	72.3%
Institute for Electric Innovation[4]	Dec 2022 (IEI)	120.0	165.0	72.3%

Sources: [1]FERC, *Assessment of Demand Response and Advanced Metering* 2008-2012. [2]EIA-861 Advanced Metering data files 2011-2022. [3]IEI, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid* 2021. [4]IEI, *Smart Meters at a Glance* (2024).
Note: Commission staff has not independently verified the accuracy of EIA or Edison Foundation (IEI) data. Values from source data are rounded for publication.