2025 Assessment of

Demand Response and Advanced Metering

Staff Report

FEDERAL ENERGY REGULATORY COMMISSION

December 2025

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Demand Response and Advanced Metering

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

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Acknowledgements

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1. Introduction

This report is the Federal Energy Regulatory Commission (FERC or Commission) staff's twentieth annual report on demand response and advanced metering, which is required annually by Section 1252(e)(3) of the Energy Policy Act of 2005 (EPAct 2005). Demand response is defined as changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.[1] The Energy Information Administration (EIA) defines advanced metering infrastructure (AMI) (also referred to as "advanced meters" throughout this report) as meters 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.[2] 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.[3]

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.[4]

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[1] *See also infra* note 61.

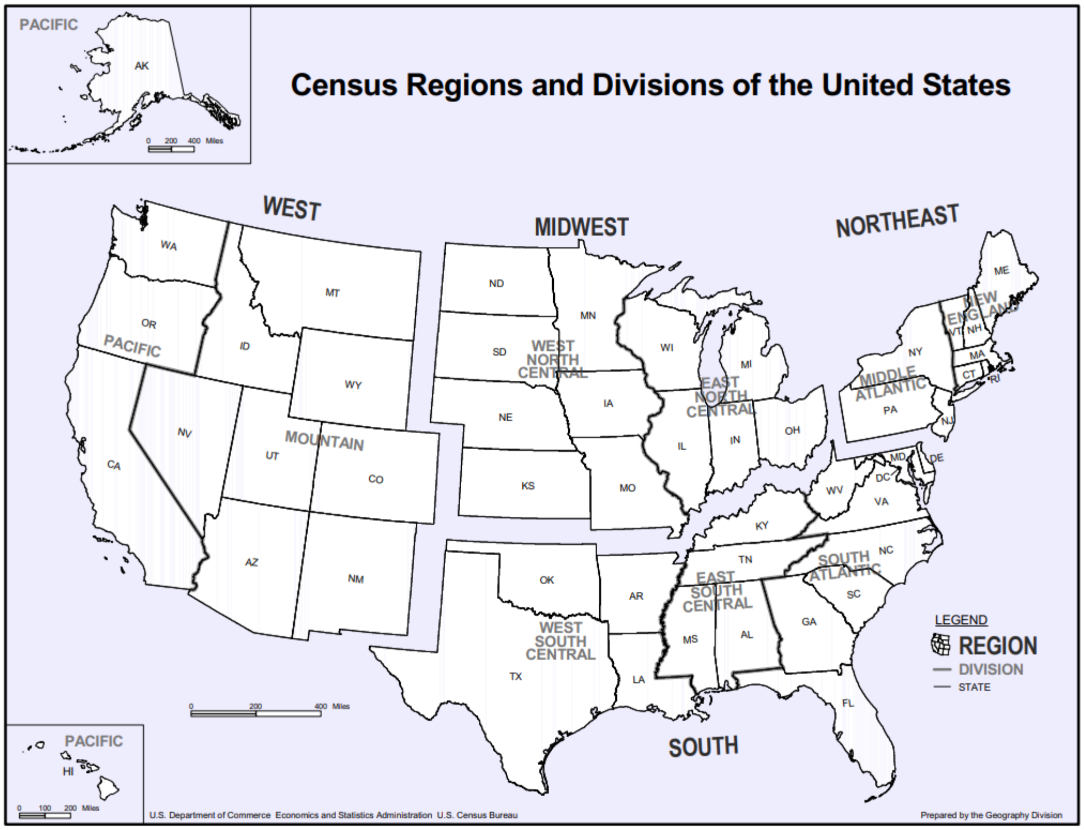
[2] Advanced meter data are used for billing and other purposes. According to EIA's definition, advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data.

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.

[3] The latest publicly available retail electricity data for the report is for the year 2023 while the latest publicly available wholesale electricity data is for the year 2024.

[4] "[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).

Figure 1-1: Map of US Census Divisions



Highlights of this report include the following:

- From 2022 to 2023, the number of advanced meters in operation in the United States increased by approximately 9.1 million to a total of 128.4 million, representing a 7.6% annual increase. According to EIA data, the 128.4 million advanced meters in operation represent 76.8% of the 167.2 million total meters in operation across all customer classes.

- The nationwide advanced meter penetration rate for each customer class was greater than 70%. At the regional level, the advanced meter penetration rate continues to vary by Census Division and customer class. In the Pacific and West South Central Census Divisions, advanced meter penetrations rates were greater than 80% for each customer class.

- From 2023 to 2024, total demand response participation in the seven U.S. wholesale markets increased by approximately 217 MW or 0.7 %, to a total of 33,272 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 Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) could be met by demand response resources in 2024. The sum of the non-coincident peak demands across all RTOs and ISOs was approximately 515 GW in 2024, compared to 512 GW in 2023.

- 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, in August 2024 the Maine Public Utilities Commission (Maine Commission) initiated an inquiry to consider the implementation of time-of-use rates for customers of the state's independently owned utilities. State governments also took actions exploring, or enabling the use of, flexible loads and distributed energy resources (DERs) for peak demand reduction. For example, the governor of Virginia signed a law directing Dominion Energy to launch a virtual power plant (VPP) pilot program consisting of DER aggregations totaling up to 450 MW.

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

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

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

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

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

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

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

2. Saturation and Penetration Rate of Advanced Meters

This chapter presents the national and regional penetration rates of advanced meters 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 2014 through 2023. According to EIA data, as of December 2023, utilities had installed and were operating 128.4 million advanced meters out of the 167.2 million total meters in the United States. This represents an advanced meter penetration rate of 76.8% and an increase of 9.1 million advanced meters, or 7.6%, from 2022 to 2023.

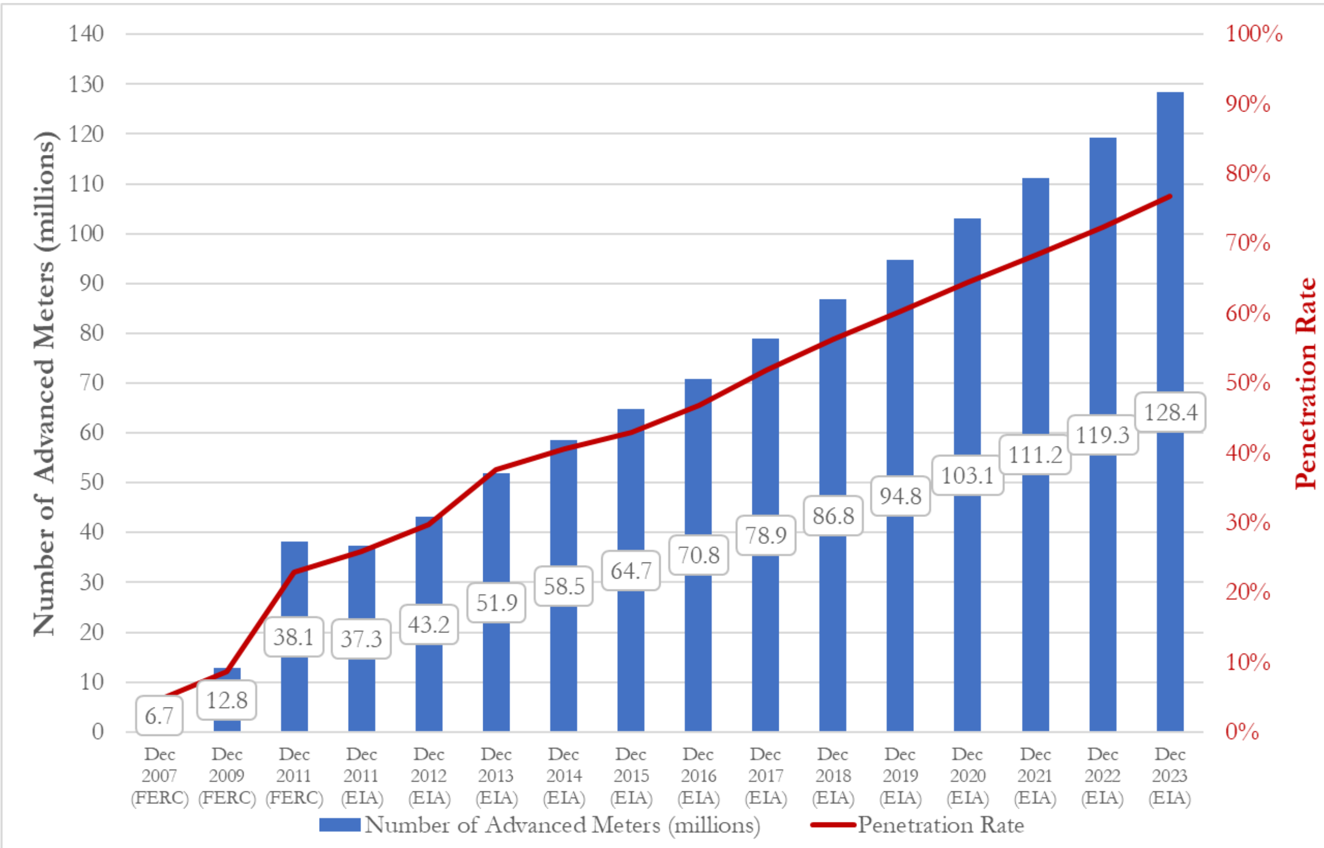
Table 2-1: Estimates of Advanced Meter Penetration Rates in the United States (2014 – 2023)

Data Source	Data as of	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rate
2014 Form EIA-861[1]	Dec 2014 (EIA)	58.5	144.3	40.5%
2015 Form EIA-861[1]	Dec 2015 (EIA)	64.7	150.8	42.9%
2016 Form EIA-861[1]	Dec 2016 (EIA)	70.8	151.3	46.8%
2017 Form EIA-861[1]	Dec 2017 (EIA)	78.9	152.1	51.9%
2018 Form EIA-861[1]	Dec 2018 (EIA)	86.8	154.1	56.4%
2019 Form EIA-861[1]	Dec 2019 (EIA)	94.8	157.2	60.3%
Institute for Electric Innovation[2]	Dec 2019 (IEI)	99.0	157.2	63.0%
2020 Form EIA-861[1]	Dec 2020 (EIA)	103.1	159.7	64.6%
Institute for Electric Innovation[2]	Dec 2020 (IEI)	107.4	159.7	67.2%
2021 Form EIA-861[1]	Dec 2021 (EIA)	111.2	162.8	68.3%
Institute for Electric Innovation[2]	Dec 2021 (IEI)	115.3	162.8	70.8%
2022 Form EIA-861[1]	Dec 2022 (EIA)	119.3	165.0	72.3%
Institute for Electric Innovation[3]	Dec 2022 (IEI)	120.0	165.0	72.3%
2023 Form EIA-861[1]	Dec 2023 (EIA)	128.4	167.2	76.8%

Sources: [1]EIA-861 Advanced Meters data files 2014-2023. [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 2023 is in Appendix II.

Figure 2-1 shows advanced meter growth in the United States from 2007 through 2023. During that 16-year period, the number of advanced meters increased by 121.7 million meters, from 6.7 million in 2007 to 128.4 million in 2023. Over the same period, the advanced meter penetration rate increased from 4.7% to 76.8%.

Figure 2-1: Advanced Meter Growth in the United States (2007–2023)



Sources: FERC, *Assessment of Demand Response and Advanced Metering* 2008-2012; EIA-861 Advanced Meters data files 2011-2023.
Note: The left axis, Number of Advanced Meters (millions), corresponds to the blue columns. The right axis, Penetration Rate, corresponds to the red line.

Table 2-2 below provides estimates of advanced meter penetration rates by Census Division and retail customer class for 2023. Utilities reported aggregate totals of advanced meters that represent penetration rates above 80% in five of the nine Census Divisions: East North Central, East South Central, 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 90.1%, the highest rate reported by utilities in any Census Division. In contrast, utilities in the New England Census Division reported totals representing an advanced meter penetration rate of 25.4%, making it the only Census Division with a penetration rate 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 70%. Overall, utilities reported the highest number of advanced meters in the residential class, which registered a penetration rate of 77.3%. Closely following this reported total, the industrial and commercial customer classes registered advanced meter penetration rates of 74.5% and 73.3%, 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, Mountain, Pacific, South Atlantic, and West South Central Census Divisions. The industrial customer class had the highest advanced meter penetration rates in the Middle Atlantic, New England, and West North Central Census Divisions. Each customer class had advanced meter penetration rates above 80% in the Pacific and West South Central Census Divisions.

Table 2-2: Advanced Meter Penetration Rate by Census Division and Customer Class (2023)

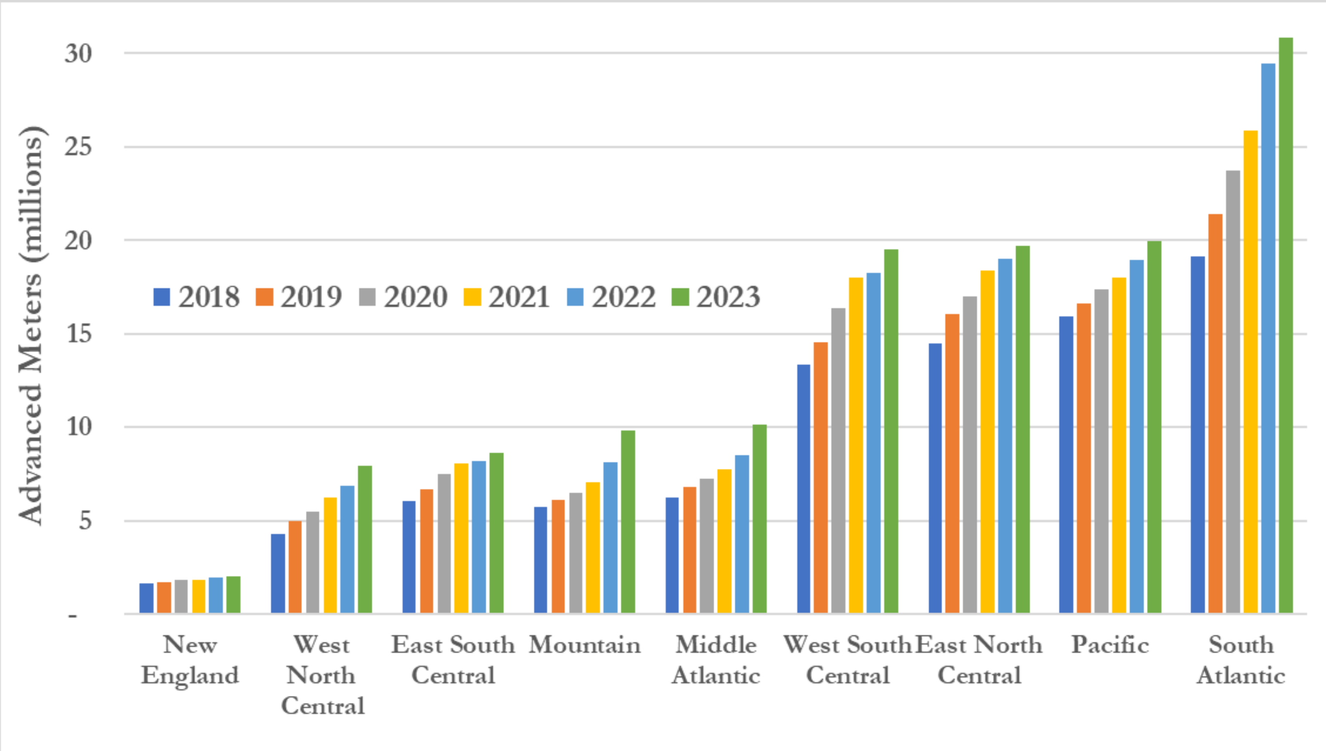
Census Division	Customer Class			
	Residential	Commercial	Industrial	All Classes
East North Central	81.7%	78.1%	71.2%	81.3%
East South Central	83.0%	78.2%	78.9%	82.3%
Middle Atlantic	53.1%	46.6%	65.6%	52.3%
Mountain	77.1%	65.8%	69.9%	75.7%
New England	25.4%	25.4%	25.5%	25.4%
Pacific	83.3%	83.2%	83.0%	83.3%
South Atlantic	89.0%	86.0%	66.5%	88.6%
West North Central	67.2%	60.1%	72.5%	66.4%
West South Central	90.5%	87.9%	80.0%	90.1%
All Regions	77.3%	73.3%	74.5%	76.8%

Sources: 2023 Form EIA-861 Advanced_Meters_2023 data file and 2023 Form EIA-861 Utility_Data_2023 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 below shows the number of advanced meters in operation by Census Division from 2018 to 2023. 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 2023 than in 2022. The Mountain Census Division experienced the largest increase from 2022 to 2023, where utilities reported over 1.6 million more advanced meters, an increase of 20%. Within the Mountain Census Division, the utilities that reported the largest increases in the number of advanced meters include PacifiCorp in Utah (850,000 advanced meters in 2023), Public Service Co. of Colorado (354,000), Tucson Electric Power Co. in Arizona (60,000), and El Paso Electric Co. in New Mexico (56,000).

Over the same period, utilities also installed more advanced meters in the Middle Atlantic (1,639,000 new meters), South Atlantic (1,365,000), West South Central (1,232,000), West North Central (1,040,000), Pacific (1,009,000), East North Central (660,000), East South Central (434,000), and New England (96,000) Census Divisions.

Figure 2-2: Number of Advanced Meters by Census Division (2018 – 2023)



Sources: EIA-861 Advanced Meters data files 2018 – 2023.

Developments and Issues in Advanced Metering

State Legislative and Regulatory Activities Related to Advanced Metering

Several states have taken actions related to AMI.[5] We discuss some of those actions here.

Colorado. On May 20, 2025, the governor of Colorado signed a bill requiring utilities to notify residential customers prior to installing AMI and to explain their right to refuse AMI installation.[6] The law requires qualifying utilities that plan to deploy AMI for residential customers on or after September 1, 2025, to submit a customer communication plan to the Colorado Public Utilities Commission on or before December 31, 2025, that includes information regarding how utilities will: (1) communicate with residential customers before installing AMI on their properties, with the requirement that communications must be sent out 90, 60, and 30 days before the installation; (2) communicate the residential customer's right to not have AMI installed and receive non-advanced meters instead if requested; and (3) communicate to new

[5] *See supra* note 2.

[6] Smart Meter Opt-In Program, H.B. 25-1175, 75th Gen. Assemb. (2025) (Colo.) (enacted),https://leg.colorado.gov/sites/default/files/2025a_1175_signed.pdf.

residential customers about whether the property already has AMI installed and their right to have non-advanced meters instead if requested.[7] The law also requires qualifying utilities that plan to deploy AMI for residential customers on or after September 1, 2025, to: (1) make reasonable efforts to notify the customer before arriving at the customer's property and provide an opportunity to defer or reject the AMI installation; (2) maintain a phone line and a public website with information regarding customers' right to remove AMI and replace it with non-advanced meters; (3) only install AMI that complies with Federal Communications Commission requirements for radio frequency; and (4) establish and maintain a public website that includes information on customer data privacy and radio frequency communications in relation to AMI.[8]

Kentucky. On July 22, 2025, the Kentucky Public Service Commission (Kentucky Commission) issued an order granting the Kentucky Power Company's (Kentucky Power) application for a certificate of public convenience and necessity (CPCN) for the deployment of AMI, granting its request to establish a regulatory asset to recover the cost of AMI deployment, and rejecting its request for deviations and waivers from certain regulations.[9] Kentucky Power proposes to replace its AMR meters with AMI throughout its service territories, and plans to begin installation in 2026 with full deployment expected by the end of 2029.[10] In granting the CPCN, the Kentucky Commission found that Kentucky Power had demonstrated that the proposed AMI project is needed to provide adequate, efficient, and reasonable service and that it evaluated alternatives and analyzed the cost and benefits of the options to determine that AMI installation was not wasteful duplication.[11] In granting Kentucky Power's request to establish a regulatory asset for the installation of the AMI meters, the Kentucky Commission stated that it will review all capital expenditures related to the project for reasonableness in a future rate case and set certain requirements for reporting of expenses and project progress.[12]

New Mexico. On February 6, 2025, the New Mexico Public Regulation Commission (New Mexico Commission) issued a Notice of Proposed Rulemaking (NOPR) initiating a proceeding to establish a statewide framework for electric utility grid modernization and distribution system planning that includes

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[7] *Id.* at 2.

[8] *Id.* at 3.

[9] *Electronic Application of Application of Kentucky Power Company for (1) a Certificate of Public Convenience and Necessity Authorizing the Deployment of Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief*, Docket No. 2024-00344, (Kentucky Commission, July 22, 2025), https://psc.ky.gov/pscscf/2024%20Cases/2024-00344//20250722_PSC_ORDER.pdf.

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

[11] *Id.* at 10-11.

[12] *Id.* at 13-17.

new requirements for AMI programs.[13] Among other items, the NOPR proposes new requirements related to AMI deployment, performance standards, and integrated planning. For example, each utility would be required to: (1) quantify the benefits of its AMI proposal and demonstrate how the utility will fully use the technology; (2) demonstrate how the technology would enable two-way communication, enable real-time monitoring, and support grid applications such as demand response, time-of-use rates, outage management, and integration of DERs; and (3) show that AMI data communications are capable of receiving continuous signals from all regions of the service territory. Except for projects replacing equipment at the end of its useful life or required to comply with legal requirements, the proposed rule also requires utilities to justify all grid modernization investments and include a comparison against traditional distribution alternatives. The NOPR record closed on May 30, 2025. Issuance of a final rule is still pending.

New York. On June 13, 2025, the New York Public Service Commission (New York Commission) accepted a petition from National Grid to revise its bill estimation procedures for both gas and electric residential customers with AMI meters in advance of the completed implementation of the Company's AMI network.[14] In November 2020, the New York Commission approved National Grid's plan to implement AMI in its upstate New York electric and gas service territories over the course of approximately six years, including installing meters and back-office information technology, such as a meter data management system.[15] The bill estimation procedures are necessary for cases where National Grid cannot collect meter readings due to reasons such as an inaccessible meter, a broken meter, or adverse weather conditions.[16] The revised bill estimation procedures will use either: (1) calculated or scaled average daily usage from National Grid's meter data management system or (2) estimated usage from its customer service system for customers with a non-AMI meter, or an AMI meter for which the meter data management system cannot provide a meter reading or estimate.[17]

Rhode Island. On May 20, 2025, the Rhode Island Public Utilities Commission (Rhode Island Commission) issued an order approving Rhode Island Energy's Advanced Metering Functionality (AMF) Business Case and cost recovery for the deployment of an AMF-based metering system with certain

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[13] *In the Matter of a Rulemaking to Implement the Grid Modernization Statute, NMSA 1978, Section 62-8-13 (2021) of the Public Utility Act,* Docket No. 22-00089-UT, (New Mexico Commission, Feb. 6, 2025), https://api.realfile.rtsclients.com/PublicFiles/9ce35ae9dd194163979349178e937b5f/25457dc8-956a-4748-8f47-ea8441b775e5/22-00089-UT-2025-02-06-NOPR%20Order.pdf

[14] *Petition of Niagara Mohawk Power Corporation d/b/a National Grid for Approval of Advanced Metering Infrastructure Bill Estimation Procedures,* Case 23-M-0658 (New York Commission June 13, 2025).

[15] *Id.* at 2.

[16] *Id.* at 4.

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

conditions.[18] Rhode Island Energy's proposal defines AMF as "the functionality that comes from the broader deployment of [AMI] hardware and software solutions needed to utilize the smart meter data in a timely and efficient manner."[19] The Rhode Island Commission found that there is a need for Rhode Island Energy to transition its AMR-based metering system to a system that uses AMF, however; the Rhode Island Commission rejected the proposed AMF cost recovery factor and instead directed Rhode Island Energy to recover costs through the existing infrastructure, safety, and reliability process.[20] The Rhode Island Commission set a capital cost recovery cap of $15.3 million and excluded meter data management system costs from eligibility for rate base recovery. Additionally, the Rhode Island Commission set certain conditions related to (1) meter functionality; (2) service quality mechanisms, and (3) how the AMF program will interact with certain other Rhode Island Energy customer-facing programs.[21] The order provides customers with the option to opt out of the installation of the new meters.[22]

[18] *In RE: Rhode Island Energy Advanced Metering Functionality Business Case and Cost Recovery Proposal*, Docket No. 22-49-EL, (Rhode Island Commission, May 20, 2025), https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2025-05/RI%20Energy%2022-49-EL%20Ord25353%20AMF%20%28final%29%205-20-25%20w-Seal.pdf.

[19] *Id.* at 1.

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

[21] *Id.* at 26-29.

[22] *Id.* at 5-6.

3. Annual Resource Contribution of Demand Resources

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

Retail Demand Response Programs

Table 3-1 below presents data on potential peak demand savings for 2022 and 2023 from retail demand response programs by Census Division. The term "potential peak demand savings" refers to "the total demand savings that could occur at the time of the system peak hour assuming all demand response is called."[23] From 2022 to 2023, potential peak demand savings in the United States increased by approximately 94 MW, or 0.3%, from 30,448 MW in 2022 to 30,542 MW in 2023. On a regional basis, however, only three of the nine Census Divisions experienced increases in annual peak demand savings from 2022 to 2023.

Table 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2022 and 2023)

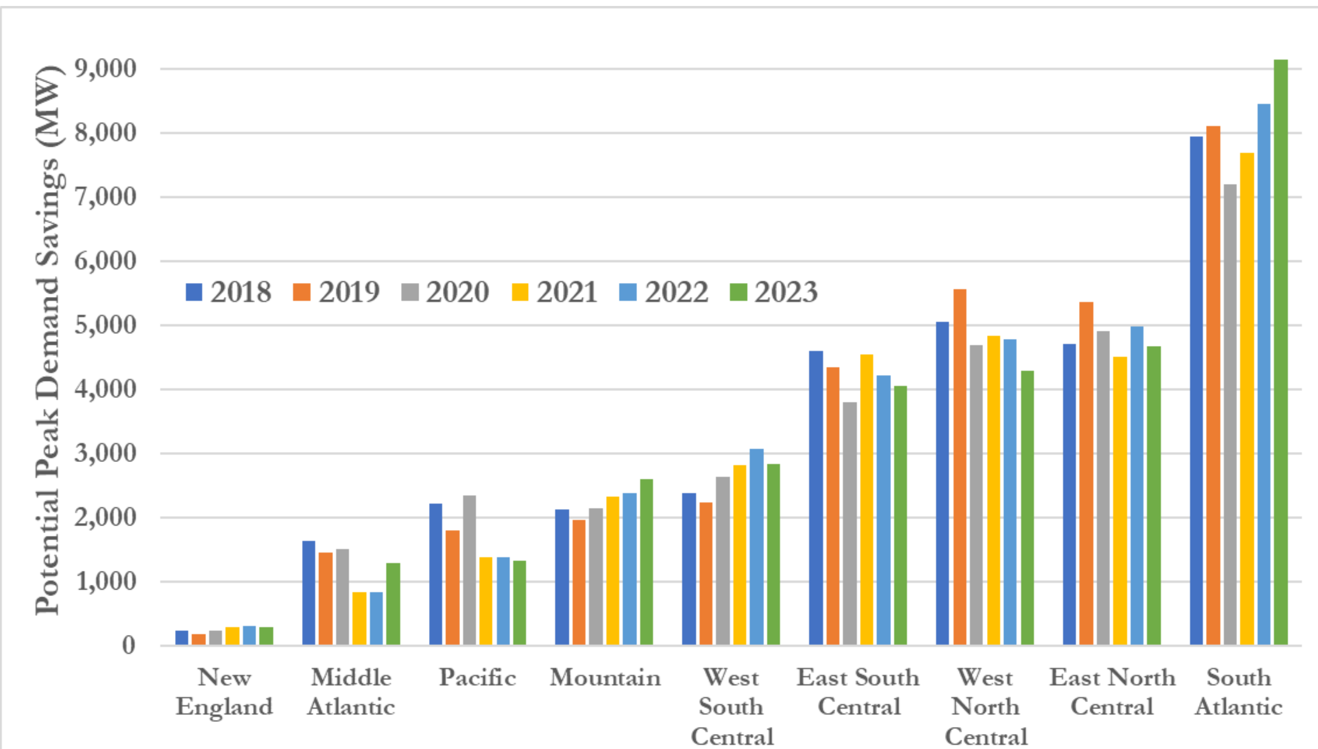
Census Division	Annual Potential Peak Demand Savings (MW)		Year-over-Year Change	
	2022	2023	MW	%
East North Central	4,974.0	4,680.8	-293.2	-5.9%
East South Central	4,223.4	4,062.6	-160.8	-3.8%
Middle Atlantic	842.1	1,303.7	461.6	54.8%
Mountain	2,389.4	2,602.7	213.2	8.9%
New England	309.2	295.1	-14.0	-4.5%
Pacific	1,390.3	1,330.0	-60.3	-4.3%
South Atlantic	8,449.2	9,146.4	697.2	8.3%
West North Central	4,787.4	4,285.9	-501.5	-10.5%
West South Central	3,082.6	2,834.7	-247.8	-8.0%
Total	**30,447.6**	**30,542.0**	**94.4**	**0.3%**

Sources: 2022 Form EIA-861 Utility_Data_2022 data file, 2022 Form EIA-861 Demand_Response_2022 data file, 2023 Form EIA-861 Utility_Data_2023 data file, 2023 Form EIA-861 Demand_Response_2023 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

[23] 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 by Census Division for 2018 through 2023. Over this period, the amount of potential peak demand savings varied significantly by each Census Division. From 2022 to 2023, the Middle Atlantic, Mountain, and South Atlantic Census Divisions experienced increases in potential peak demand savings. In aggregate, utilities in the South Atlantic Census Division reported the largest increase, reporting approximately 697 MW, or 8.3%, more potential peak demand savings in 2023 than in 2022. Utilities in the South Atlantic Census Division with notable potential peak demand savings increases include Duke Energy Progress in North Carolina and South Carolina Public Service Authority (Santee Cooper), which reported approximately 356 MW and 120 MW of additional peak demand savings, respectively. Utilities in the Middle Atlantic Census Division reported approximately 462 MW, or 54.8%, more potential peak demand savings in 2023, the largest percent increase among Census Divisions. Utilities in the Middle Atlantic Census Division with notable increases in potential peak demand savings increases include Consolidated Edison Co. and Niagara Mohawk Power Corp., both in New York, reporting approximately 93 MW and 50 MW of additional peak demand savings, respectively. Finally, in the Mountain Census Division, Public Service Co. of Colorado reported approximately 149 MW more potential peak demand savings in 2023 than 2022, the largest increase in that Census Division.

Figure 3-1: Potential Peak Demand Savings (MW) from Retail Demand Response Programs by Census Division (2018 – 2023)



Sources: EIA-861 Demand Response data files 2018 – 2023.

While potential peak demand savings increased nationwide, six of the nine Census Divisions experienced aggregate decreases in potential peak demand savings from 2022 to 2023. In the East North Central Census Division, for instance, potential peak demand savings decreased largely because of declines at utilities in the states of Michigan and Indiana. Similarly, utilities reported aggregate decreases at the state level in

Kentucky, Tennessee, and Mississippi in the East South Central Division; Massachusetts and New Hampshire in the New England Census Divisions; and California and Oregon in the Pacific Census Division. The declines in the West North Central and West South Central Census Divisions occurred primarily in two utilities that reported large decreases in potential peak demand savings.

Table 3-2 below presents the relative contribution of retail potential peak demand savings in 2023 from the residential, commercial, and industrial customer classes. In 2023, utilities reported approximately 14,000 MW of potential peak demands savings from the industrial customer class, which is the largest share—45.3%—of potential peak demand among customer classes. The relative contributions to potential peak demand savings by the residential and commercial customer classes in 2023 were 31.7% and 23.0%, respectively. The customer class with the largest amount of potential peak demand savings varied for each Census Division. The residential class provided the largest amounts of potential peak demand savings in the Mountain, New England, South Atlantic, and West North Central Census Divisions. The commercial class provided the largest amount of potential peak demand savings in the Middle Atlantic Census Division. The industrial class provided the largest amounts of potential peak demands 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 (2023)

Census Division	Customer Class			
	Residential (MW)	Commercial (MW)	Industrial (MW)	All Classes (MW)
East North Central	861.92	829.38	2,989.50	4,680.80
East South Central	363.28	104.00	3,595.32	4,062.60
Middle Atlantic	242.06	928.50	133.18	1,303.74
Mountain	1,233.79	414.02	954.86	2,602.66
New England	128.45	106.78	59.90	295.13
Pacific	454.84	290.03	585.14	1,330.00
South Atlantic	3,997.15	2,601.26	2,547.99	9,146.41
West North Central	1,924.58	824.56	1,536.78	4,285.92
West South Central	460.56	936.59	1,437.59	2,834.74
Total	**9,666.60**	**7,035.11**	**13,840.27**	**30,541.98**

Sources: 2023 Form EIA-861 Demand_Response_2023 data file and 2023 Form EIA-861 Utility_Data_2023 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 presents estimates of participation in wholesale demand response programs in the seven RTOs and ISOs[24] in 2023 and 2024. Demand response participation increased in the wholesale markets overall by approximately 217 MW, or 0.7%, from 2023 to 2024. On a regional basis, demand response totals increased in five of the wholesale markets but declined in two of them. ERCOT experienced the largest annual increase, reporting approximately 486 MW more demand response resources in 2024. Based on the reported data, approximately 6.5% of the wholesale market non-coincident peak demand for all RTOs and ISOs could be met by demand response resources in 2024. The sum of the non-coincident peak demands across all RTOs and ISOs was approximately 515 GW in 2024.

In CAISO, demand response capacity increased by approximately 219 MW, or 5.3%, from 4,154 MW in 2023 to 4,373 MW in 2024. Third party demand response participation[25] averaged 188 MW in 2024, which is down from 210 MW reported in 2023.[26] Utility demand response participation also declined in 2024, averaging 986 MW, which is down from 1,175 MW reported in 2023.

ERCOT experienced the largest net annual increase in demand response resources among organized wholesale electricity markets. From 2023 to 2024, demand response resource participation increased by approximately 486 MW, or 13.5%, from 3,613 MW to 4,099 MW. Demand response resource participation increased in ERCOT's Emergency Response Service by 286 MW, in Contingency Reserve Service[27] by 299 MW, and in Non-spinning Reserves by 215 MW. In contrast, demand response resources participating in ERCOT's Responsive Reserve Service decreased by 279 MW.

ISO-NE reported approximately 431 MW of Active Demand Capacity Resources enrolled in July 2024, the month with the highest peak demand in ISO-NE that year. This represents a 25 MW, or 5.5%, decrease in enrolled demand response compared to the 456 MW of Active Demand Capacity Resources in September 2023, the month with the highest peak demand in ISO-NE that year.

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[24] The RTOs and ISOs include the 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).

[25] Third party demand response is operated by non-utility providers under contract to supply demand response for utilities. *See* CAISO, *Demand Response Issues and Performance 2024* at 8 (Mar. 2025), https://www.caiso.com/documents/demand-response-issues-and-performance-2024-mar-14-2025.pdf.

[26] CAISO, *2024 Annual Report on Market Issues & Performance* at 319 (Aug. 2025), https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf.

[27] The ERCOT Contingency Reserve Service (ECRS) allows resources that both do and do not have under-frequency relays to provide this reserve service. This contrasts with ERCOT's Responsive Reserve Service (RRS) which allow resources controlled by high-set under-frequency relays to provide reserve service. *See* ERCOT, *2024 Annual Report on Demand Response in the ERCOT Region* at 6 (Feb. 2025), https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=1080511461.

Table 3-3: Demand Response Resource Participation in RTOs and ISOs (2023 and 2024)

RTO/ISO	2023		2024		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]	4,154.3	9.3%	4,373.0	9.0%	218.8	5.3%
ERCOT[2]	3,612.8	4.2%	4,099.1	4.8%	486.3	13.5%
ISO-NE[3]	456.0	1.9%	431.0	1.7%	-25.0	-5.5%
MISO[4]	12,663.0	10.1%	12,954.0	10.6%	291.0	2.3%
NYISO[5]	1,708.7	5.5%	1,920.9	6.1%	212.2	12.4%
PJM[6]	9,666.8	6.7%	8,526.0	5.7%	-1,140.8	-11.8%
SPP[7]	793.0	1.4%	968.0	1.8%	175.0	22.1%
Total	**33,054.5**	**6.5%**	**33,272.0**	**6.5%**	**217.4**	**0.7%**

Sources for demand resource data: [1] CAISO, 2023 and 2024 Annual Reports on Market Issues and Performance. Totals for Figure 15.3 were confirmed with the CAISO Department of Market Monitoring; [2] Estimated based on ERCOT, 2023 and 2024 Annual Reports of Demand Response in the ERCOT Region; [3] ISO-NE Monthly Market Operations Report April 2024 and December 2024; [4] Potomac Economics, 2023 and 2024 State of the Market Reports for the MISO Electricity Markets; [5] NYISO, 2023 and 2024 Annual Reports on Demand Response Programs; [6] PJM, 2023 and 2024 Demand Response Operations Markets Activity Reports. Totals represent "unique MW" (see *infra* note 31); [7] SPP, 2023 and 2024 State of the Market Reports; [8] Sources for peak demand data: CAISO 2023 and 2024 Annual Reports on Market Issues and Performance; ERCOT 2023 & 2024 Demand and Energy Reports; ISO-NE Net Energy and Peak Load Report; Potomac Economics, 2023 and 2024 State of the Market Reports for the MISO Electricity Markets; NYISO Power Trends Reports 2023 and 2024; 2023 and 2024 PJM State of the Market Report, Vol. 2; SPP 2023 and 2024 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.

MISO experienced an increase in demand response resources of approximately 291 MW, or 2.3%, from 12,663 MW in 2023 to 12,954 MW in 2024. Participation increased for Load-Modifying Resources[28] by 428 MW and for Demand Response Type I and II Resources by 167 MW. In contrast, resource participation in the Emergency Demand Response program decreased by 95 MW.[29]

[28] Load-Modifying Resources (LMRs) are capacity resources obligated to curtail in emergencies and to help satisfy planning reserve margin requirements. *See* Potomac Economics, *2024 State of the Market Report for the MISO Electricity Markets* at 98 (Jun. 2025), https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf.

[29] The values reported for Demand Response Type I and II, and Emergency Demand Response may include resources cross-registered as Load-Modifying Resources. *See Id.* at 98.

In NYISO, demand response resource registration increased by approximately 212 MW, or 12.4%, from 1,709 MW in 2023 to 1,921 MW in 2024. Demand response participation increased in NYISO's reliability-based demand response programs[30] by 195 MW and in its economic-based Demand-Side Ancillary Service Program by 19 MW.

PJM experienced a decrease in registered demand response of approximately 1,141 MW, or 11.8%, from 9,667 MW in 2023 to 8,526 MW in 2024. From 2023 to 2024, participation decreased in PJM's Economic program by 300 MW and in its Load Management program by 789 MW.[31]

SPP reported approximately 968 MW of demand response participation from 121 demand response resources in 2024. This represents a 175 MW, or 22.1%, increase from 2023, when SPP reported at total of 793 MW of demand response participation. in 2023 to 968 MW in 2024.[32]

Demand Response Deployments

RTOs and ISOs deploy demand response resources to balance supply and demand and to avoid the cost of dispatching additional generation or involuntarily curtailing load. In June 2025, a heat wave in the Mid-Atlantic and Northeast resulted in near record-breaking peak demand for electricity, which led some grid operators to issue hot weather alerts and calls for demand response. An overview of some of those actions is provided below.

In ISO-NE, demand peaked at 26,024 MW on the evening of June 24, 2025, the highest level seen in the region since 2013.[33] ISO-NE issued a Power Caution after an unexpected loss of generation and declared an Energy Emergency Alert 1. Declaring a Power Caution allows ISO-NE to take certain actions to

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[30] NYISO's reliability-based demand response programs include the Emergency Demand Response Program and the Installed Capacity – Special Case Resource Program. *See* NYISO, *2024 Annual Report on Demand Response Programs* at 1-2 (Feb. 2025), https://www.nyiso.com/documents/20142/49931415/NYISO-2024-Annual-Report-on-Demand-Response-Programs.pdf/d0a21acb-eda1-09b6-a7c0-62e627f0b01d.

[31] The values 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, *2024 Demand Response Operations Markets Activity Report* at 3 (Mar. 2025), https://www.pjm.com/-/media/DotCom/markets-ops/dsr/2024-demand-response-activity-report.pdf.

[32] SPP, *State of the Market 2024* at 41 (May 2025), https://www.spp.org/documents/73953/2024_annual_state_of_the_market_report.pdf. [33] ISO Newswire, *Hot Weather Updates: Week of June 23, 2025* (June 2025), https://isonewswire.com/2025/06/25/hot-weather-updates-week-of-june-23-2025/.

[33] ISO Newswire, *Hot Weather Updates: Week of June 23, 2025* (June 2025), https://isonewswire.com/2025/06/25/hot-weather-updates-week-of-june-23-2025/.

maintain system reliability including activating operating reserves, initiating voltage reductions, requesting emergency imports from neighboring regions, or, if needed, requesting conservation.[34]

Similarly, NYISO issued Energy Alerts and Energy Emergencies on June 24, 2025, due to an Operating Reserve deficiency.[35] The Operating Reserve deficiency was caused by high demand, stressed system conditions, and resource performance issues. These factors led NYISO to activate demand response resources among several other corrective actions including curtailing exports, dispatching generation to optimize 30-minute reserves, and purchasing emergency energy.

PJM issued Maximum Generation and Load Management Alerts during the period June 23 – 25, 2025, due to high energy demand resulting from extreme heat.[36] Such alerts from PJM notify demand response resources that they may be called upon, advise transmission owners and generators to be in a state of readiness to be dispatched if needed, and inform neighboring regions that PJM exports may be curtailed. During this period, among other actions, PJM deployed demand response resources that reduced system peaks by more than 4,000 MW. Peak demand reached approximately 162,000 MW on June 24, 2025, the third-highest all-time peak demand in PJM.

Separately, on August 11, 2025, PJM deployed demand response to maintain system reliability and minimize a load shed event after the loss of a substation in the Baltimore Gas & Electric (BGE) transmission zone.[37] Overall, PJM and BGE demand response programs reduced load by 230 MW. PJM stated that demand response and voltage reduction action that day reduced the magnitude and duration of the load shed event, from potentially 1,200 MW of load shed down to a loss of 20 MW lasting 28 minutes.

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[34] *See* ISO-NE, *What Is a Capacity Deficiency?*, https://www.iso-ne.com/about/what-we-do/in-depth/capacity-deficiency.

[35] *See* NYISO, *Major Emergency Report June 24, 2025, Operating Reserve Deficiency* (2025), https://www.nysrc.org/wp-content/uploads/2025/07/7.3.3-EC-Presentation-Major-Emergency-06.24.2025-Attachment-7.3.3.pdf.

[36] PJM Inside Lines, *Maintaining Grid Reliability Through Highest Peaks in a Decade* (July 2025), https://insidelines.pjm.com/maintaining-grid-reliability-through-highest-peaks-in-a-decade/.

[37] PJM Inside Lines, *PJM Details Its Actions to Minimize Aug. 11 Baltimore Load Shed Event* (Sep. 2025), https://insidelines.pjm.com/pjm-details-its-actions-to-minimize-baltimore-load-shed-event/.

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

As detailed in previous years' Assessments of Demand Response and Advanced Metering, regulatory bodies, reliability coordinators, RTOs and ISOs, and utilities continue to use demand response as a quantifiable, reliable resource for regional planning purposes, including meeting planning requirements, reducing demand, and meeting changing system needs in the energy and ancillary services markets. For example, on September 29, 2025, the California Public Utilities Commission (California Commission) issued an order instituting a rulemaking to assess and improve the consistency, predictability, reliability, and cost-effectiveness of demand response resources by updating the California Commission's demand response guiding principles, as well as its policies and data system and process requirements.[38] The order states that the California Commission, the California Energy Commission, and the California Legislature have all recognized the critical role of demand response in promoting reliability and reducing costs borne by ratepayers.[39] Other examples of state legislators and regulatory bodies recognizing demand response as a quantifiable, reliable resource can be found in Chapter 5: Developments and Issues in Demand Response. Additionally, as detailed earlier in this report, RTOs and ISOs deploy demand response resources to balance supply and demand and to avoid the cost of dispatching additional generation or involuntarily curtailing load. For details on the potential resource contribution from demand response programs and deployment of demand response resources in RTOs and ISOs, see Chapter 3: Wholesale Demand Response Programs and Demand Response Deployments.

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[38] *Order Instituting Rulemaking to Enhance Demand Response in California*, Docket No. R 25-09-004, (California Commission Sep. 29, 2025) https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M582/K072/582072320.PDF.

[39] *Id.* at 5.

5. Existing Demand Response and Dynamic Pricing Programs

This chapter presents regional information on retail demand response[40] and dynamic pricing[41] programs, based on EIA data. Again, FERC staff does not independently verify the accuracy of EIA data, but rather reports the data as they were reported by EIA. This chapter also summarizes selected recent federal, regional, state, and industry actions and developments related to demand response.

Enrollment in Retail Demand Response and Dynamic Pricing

Table 5-1 below presents enrollment by customer account in retail incentive-based demand response programs for each of the nine Census Divisions in 2022 and 2023. U.S. customer enrollment in these programs increased by approximately 247,000 customers, or 2.4%, from 10.3 million customers in 2022 to 10.6 million customers in 2023. This growth can be attributed to increased enrollment reported by utilities in the East North Central, East South Central, Middle Atlantic, New England, Pacific, and South Atlantic Census Divisions.

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[40] 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.

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

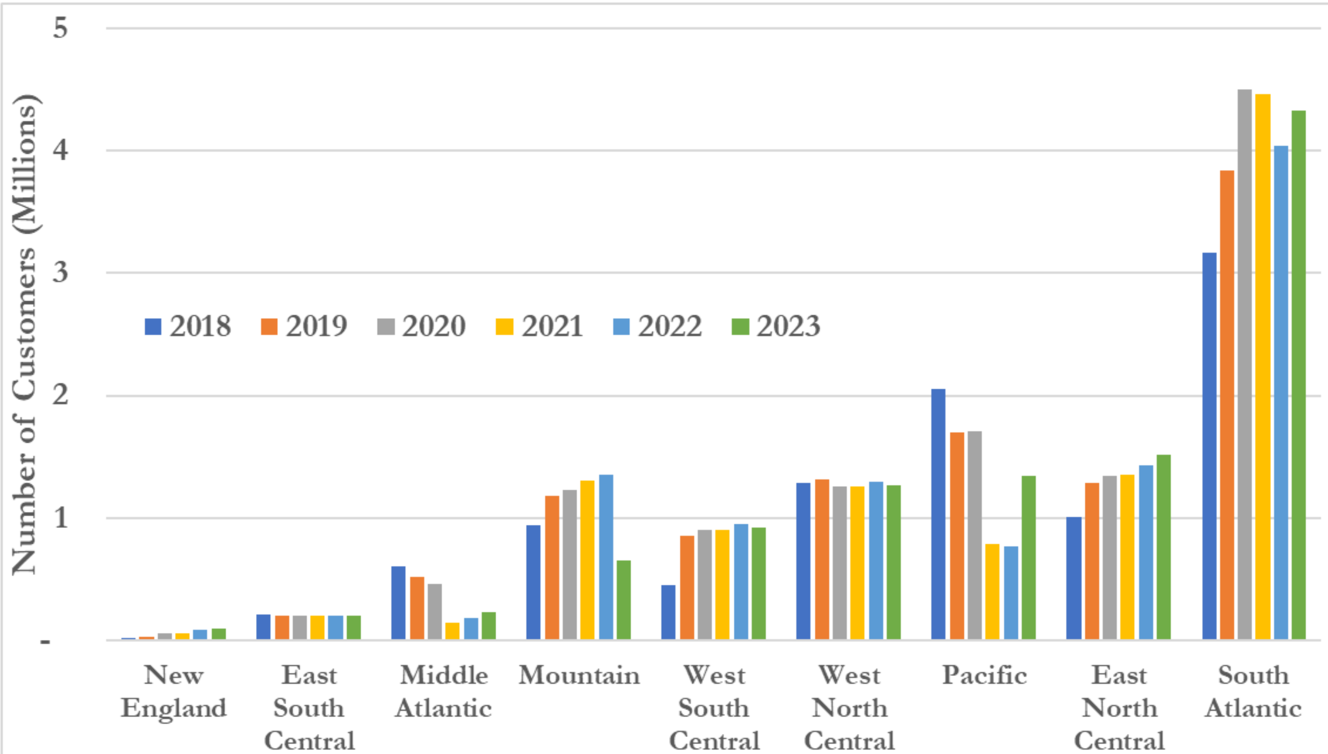
Table 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2022 and 2023)

Census Division	Enrollment in Retail Demand Response Programs		Year-over-Year Change	
	2022	2023	Customers	%
East North Central	1,431,542	1,516,053	84,511	5.9%
East South Central	203,712	204,373	661	0.3%
Middle Atlantic	184,804	230,625	45,821	24.8%
Mountain	1,356,157	653,102	-703,055	-51.8%
New England	86,732	100,576	13,844	16.0%
Pacific	773,107	1,348,727	575,620	74.5%
South Atlantic	4,034,799	4,328,784	293,985	7.3%
West North Central	1,295,155	1,265,964	-29,191	-2.3%
West South Central	953,766	919,050	-34,716	-3.6%
Total	**10,319,774**	**10,567,254**	**247,480**	**2.4%**

Sources: 2022 Form EIA-861 Utility_Data_2022 data file, 2022 Form EIA-861 Demand_Response_2022 data file, 2023 Form EIA-861 Utility_Data_2023 data file, and 2023 Form EIA-861 Demand_Response_2023 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 enrollment by customer account in retail incentive-based demand response programs in each Census Division from 2018 to 2023. Over this period, trends in customer enrollment in such programs varied across Census Divisions. From 2022 to 2023, utilities in six of the nine Census Divisions experienced increases in customer enrollment in retail incentive-based demand response programs. In aggregate, utilities in the Pacific Census Division reported the largest increase among Census Divisions, reporting approximately 576,000 additional customers, or a 74.5% increase. This increase can primarily be attributed to Puget Sound Energy Inc. in Washington State, which reported approximately 525,000 customers enrolled in retail incentive-based demand response programs in 2023. Utilities in other Census Divisions also experienced notable increases in retail demand response programs enrollment. These include Potomac Electric Power Co. in Maryland (344,000 additional customers enrolled), Delmarva Power in Delaware (116,000) and Delmarva Power in Maryland (77,000) in the South Atlantic Census Division; and DTE Electric Co. (54,000) and Consumers Energy Co. (37,000) in Michigan in the East North Central Census Division.

Figure 5-1: Customer Enrollment in Retail Demand Response Programs by Census Division (2018 – 2023)



Sources: EIA-861 Demand Response data files 2018 – 2023.

While nationwide customer enrollment in retail demand response programs grew from 2022 to 2023, utilities in the Mountain, West North Central, and West South Central Census Divisions reported approximately 703,000, 20,000, and 35,000 fewer customers enrolled. The decline in the Mountain Census Division was due primarily to one utility that reported approximately 720,000 fewer customers enrolled in 2023 compared to 2022. The decreases in the West North Central and West South Central Census Divisions resulted from aggregate declines reported by utilities in Arkansas, Kansas, Oklahoma, Minnesota, Missouri, North Dakota, South Dakota and Texas.

Turning to dynamic pricing, Table 5-2 below illustrates customer enrollment in retail dynamic pricing programs for each of the nine Census Divisions in 2022 and 2023. From 2022 to 2023, U.S. customer enrollment in these program programs increased by approximately 2.6 million customers, or 16.9%. Seven Census Divisions experienced aggregated increases in customer enrollment. The East North Central Division experienced the largest aggregate increase, with utilities reporting approximately 1.5 million additional customers enrolled in retail dynamic pricing programs in 2023. The significant annual enrollment increases in the East North Central Division resulted from a large rise in customers enrolled in Michigan, mostly from Consumers Energy Co. Utilities in the East South Central, Middle Atlantic, Mountain, New England, West North Central, and West South Central Census Divisions also reported more customers enrolled in retail dynamic pricing programs in 2023 compared to 2022. While overall enrollment in retail dynamic pricing programs increased nationwide, the Pacific and South Atlantic Census Divisions experienced aggregated decreases in customer enrollment. Utilities in the South Atlantic and Pacific Census

Divisions reported approximately 350,000 and 211,000 fewer customers, respectively, enrolled in retail dynamic pricing programs in 2023.

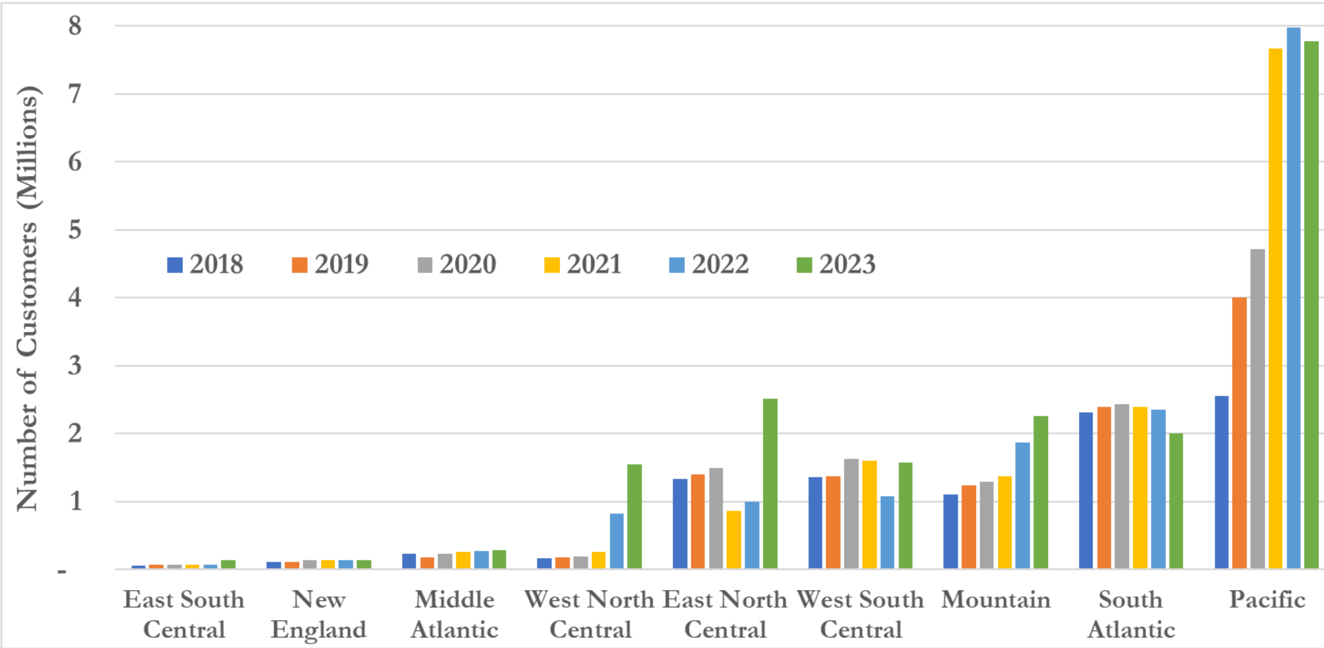
Table 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2022 and 2023)

Census Division	Enrollment in Dynamic Pricing Programs		Year-over-Year Change	
	2022	2023	Customers	%
East North Central	997,574	2,512,498	1,514,924	151.9%
East South Central	69,859	141,917	72,058	103.1%
Middle Atlantic	276,014	279,248	3,234	1.2%
Mountain	1,868,528	2,253,880	385,352	20.6%
New England	136,319	144,308	7,989	5.9%
Pacific	7,983,495	7,772,829	-210,666	-2.6%
South Atlantic	2,357,868	2,005,858	-352,010	-14.9%
West North Central	828,644	1,549,726	721,082	87.0%
West South Central	1,078,678	1,579,824	501,146	46.5%
Total	**15,596,979**	**18,240,088**	**2,643,109**	**16.9%**

Source: 2022 Form EIA-861 Dynamic_Pricing_2022 data file, 2022 Form EIA-861 Utility_Data_2022 data file, 2023 Form EIA-861 Dynamic_Pricing_2023 data file, and 2023 Form EIA-861 Utility_Data_2023 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 Division from 2018 through 2023. Over this period, customer enrollment showed a consistent upward trend across all Census Divisions except for the East North Central, West South Central, and South Atlantic Census Divisions. Customer enrollment fluctuated in the East North Central and West South Central Census Divisions and remained relatively stable in the South Atlantic Census Divisions over the same time. Utilities in the Pacific Census Division continued to report the largest aggregate number of customers enrolled in retail dynamic pricing programs, with approximately 7.8 million customers enrolled in 2023, however, the total number of enrolled customers declined by 201,666 customers or 2.6% between 2022 and 2023. Notably, Southern California Edison reported approximately 150,000 more customers enrolled in retail dynamic pricing programs in 2023 compared to 2022. Utilities in other Census Divisions also experienced significant increases in customer enrollment from 2022 to 2023. For example, Consumers Energy Co. of Michigan in the East North Central Census Division reported 1.5 million additional customers enrolled in retail dynamic pricing programs in 2023. Public Service Co. of Oklahoma in the West South Central Census Division and Public Service Co. of Colorado in the Mountain Census Division also reported 465,000 and 350,000 additional customers, respectively, enrolled in retail dynamic pricing programs in 2023. While the Pacific Census Division reported the largest aggregate number of customers enrolled, the East North Central, West North Central, and West South Central Census Divisions reported the highest year-over-year increases from 2022 to 2023, with approximately 1.5 million, 720,000, and 500,000 more customers, respectively, enrolled in retail dynamic pricing programs.

Figure 5-2: Customer Enrollment in Retail Dynamic Pricing Programs by Census Division (2018 – 2023)



Sources: EIA-861 Dynamic Pricing data files 2018 – 2023.

FERC Demand Response Orders and Activities

MISO Modification to Demand Resource Participation Requirements (ER25-1729-000)

On July 18, 2025, the Commission accepted MISO's proposal to revise its tariff revisions to modify its demand resource participation requirements.[42] MISO stated that its proposal was aimed at ensuring that the participation of demand resources is less prone to Tariff violations, potential gaming, market manipulation, and fraud, and will reduce or prevent: (1) payments for nonexistent or overstated curtailments; (2) inaccurate or inflated baselines on which curtailments are based; and (3) fraudulent registration of resources.[43] MISO stated that it submitted its filing in response to four Commission orders[44] that addressed assertions of tariff violations, market manipulation, and fraud relating to certain demand resources'

[42] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,060 (2025).

[43] MISO, Transmittal, Docket No. ER25-1729, at 1, 7 (filed Mar. 21, 2025).

[44] *See Big River Steel LLC & Entergy Ark. LLC,* 184 FERC ¶ 61,111 (2023); *Linde Inc. and Northern Indiana Public Service Company LLC,* 186 FERC ¶ 61,009 (2024); *Ketchup Caddy, LLC & Philip Mango*, 186 FERC ¶ 61,132 (2024); *Voltus, Inc. & Gregg Dixon*, 190 FERC ¶ 61,008 (2025).

participation in MISO's markets.[45] Notably, the accepted tariff revisions: (1) clarify the expectation that demand resources should respond to MISO's instructions, require demand resources to attest in writing that they made a load reduction in response to MISO's instructions, and require that demand resources submit meter data demonstrating the load reduction to MISO within a specified timeframe; (2) explicitly allow MISO's Independent Market Monitor to mitigate the offers of demand response resources if the offer is not deemed economic; (3) set the baseline load for a resource by using the five lowest average load days over the prior 45-day period should a resource have too few non-event days rather than the five highest average load days across the entire 45-day period; and (4) clarify that any entity offering into MISO's markets must have the legal right to make the resource available to respond to a scheduling instruction on the terms it submits, whether through ownership or a contractual relationship.

MISO Elimination of Dual Registration of Demand Response (ER25-2050-000)

On July 18, 2025, the Commission accepted MISO's proposed tariff revisions to remove the ability for market participants to register a resource both as an Emergency Demand Response resource and as a Load Modifying Resource in the MISO Planning Resource Auction.[46] MISO noted in its proposal that market participants had an incentive to register demand-side resources as both Load Modifying and Emergency Demand Response resources.[47] Prior to the Commission's Order accepting its tariff changes, under MISO's Emergency Operating Procedures, Load Modifying Resources were dispatched prior to deploying Emergency Demand Response Resources, which are dispatched using Security Constrained Economic Dispatch.[48] This sequencing deployed resources compensated through capacity payments prior to resources only compensated through energy payments.[49] Previously, a resource that had registered as both types of resources and offered its Emergency Demand Response resource as zero megawatts would receive Capacity payment compensation for its Load Modifying Resource participation while reducing the likelihood of being called to perform as either type of resource.[50]

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[45] MISO, Transmittal, Docket No. ER25-1729 (filed Mar. 21, 2025).

[46] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,059, at P 1 (2025). MISO, Transmittal, Docket No. ER25-2050, at 1, 7 (filed Apr. 21, 2025).

[47] *Id.* at P 6.

[48] *Id.* at P 8.

[49] *Id.* at P 8.

[50] *Id. at P* 8.

PJM Automating Bid Duration for Economic Load Response Participants (ER24-3135-000, -001)

On September 27, 2024, PJM filed proposed tariff revisions to allow Economic Load Response (ELR) participants to specify a maximum down time during which end-use loads may be curtailed, and a minimum release time between load curtailments.[51] On November 26, 2024, the Commission accepted PJM's proposed revisions subject to a further compliance filing.[52] Under the system in place at the time, PJM had committed ELR participants to curtail load in both the day-ahead energy market and the real-time energy market when the projected locational marginal price for energy was projected to be greater than an ELR participant's offer price, subject to parameter constraints. ELR participants could specify certain offer parameters when submitting their energy offers, except for a maximum down time, or the maximum amount of time that load may be curtailed, and a minimum release time, or the minimum amount of time that must pass before load can be curtailed again after being dispatched in the same operating day. PJM stated that ELR participants could limit bid durations manually by marking a demand response resource as unavailable for specific times, but the proposed tariff revisions would extend the ability to automate bid duration parameters for ELR participants.[53] On February 27, 2025, the Commission accepted PJM's compliance filing defining maximum down time and minimum release time.[54]

PJM Expansion of DR Availability Window and Amendments to Winter Peaking Load Methodology (ER25-1525)

On May 5, 2025, the Commission accepted PJM's proposal to revise Article 1 of the PJM Reliability Assurance Agreement Among Load Serving Entities (RAA) to modify the definitions of Annual Demand Resource and Summer-Period Demand Resource and the calculation of Winter Peak Load.[55] PJM proposed to redefine Annual Demand Resource and Summer-Period Demand Resource to provide for a 24-hour availability window throughout the year effective with the 2027/2028 delivery year as opposed to specified seasonal availability windows defined in its RAA. PJM also proposed to revise the Effective Load Carrying Capability accreditation calculation of demand resources by amending the definition of Winter Peak Load for demand resources to base the Winter Peak Load calculation on each demand resource customer's load during a PJM-selected consistent peak hour across five coincident peak days in winter.

Commission Enforcement Activity

On January 6, 2025, the Commission issued an order approving a Stipulation and Consent Agreement that resolved the Commission's Office of Enforcement's investigation of an aggregator of retail customers,

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[51] PJM, Transmittal, Docket No. ER24-3135 (filed Jan. 23, 2025).

[52] *PJM Interconnection, L.L.C.,* 189 FERC ¶ 61,146 (2024).

[53] *Id.* at PP 3, 5.

[54] *PJM Interconnection, L.L.C.*, Docket No. ER24-3135-001 (Feb. 27, 2025) (delegated order).

[55] *PJM Interconnection, L.L.C.,* 191 FERC ¶ 61,103 (2025).

Voltus, Inc. (Voltus), and its former CEO, and whether they violated MISO's Tariff or Commission regulations.[56] In the Stipulation and Consent Agreement, Voltus agreed to disgorge $7,080,543 in revenue that it earned during the Relevant Period, pay a civil penalty of $10,919,457 to the United States Treasury and provide compliance monitoring reports to the Commission's Office of Enforcement. In addition, the CEO agreed to pay a civil penalty of $1,000,000 to the United States Treasury, step down from Voltus's Board of Directors, neither pursue nor accept any role with Voltus or any Voltus successor entity or affiliate going forward.

On December 5, 2024, the Commission issued an Order Assessing Civil Penalties (Order) against Ketchup Caddy, LLC (Ketchup Caddy) and its co-owner for violations of the Federal Power Act, the Commission's regulations, and the MISO's Tariff. Specifically, the Commission found that these parties engaged in fraudulent activity and market manipulation, and offered uncontracted resources into MISO's capacity market without the demand resources' knowledge or consent.[57] The Commission assessed civil penalties of $25,000,000 plus interest against Ketchup Caddy and $1.5 million plus interest against its co-owner, as well as ordered $506,502 in disgorgement, plus interest. After filing a complaint in the United States District Court for the Central District of Illinois[58], Enforcement staff obtained a default judgment in the amount of $26,323,033.17 against Ketchup Caddy and $2,262,137.99 against its co-owner.[59] Enforcement staff will take steps to execute on the judgment.

Other Federal Demand Response Activities

Federal Communications Commission

On June 9, 2025, the Federal Communications Commission (FCC) issued a declaratory ruling granting Edison Electric Institute's petition requesting clarification that utilities have prior express consent under the Telephone Consumer Protection Act to send non-telemarketing demand response calls and texts when customers give their phone numbers to a utility.[60] The FCC confirmed that such calls and texts are closely related to utility service and thus utilities can make critical, time-sensitive demand response communications to their customers without having to receive additional consent from each customer.[61] In the ruling, the

[56] *Voltus Inc. and Gregg Dixon*, 190 FERC ¶ 61,008 (2025).

[57] *Ketchup Caddy, LLC and Philip Mango,* 189 FERC ¶ 61,176 (2024).

[58] *FERC v. Ketchup Caddy, LLC, et al.* (C.D. Ill. 25-cv-3116).

[59] *Id.,* ECF No. 8.

[60] *In the Matter of Rules and Regulations Implementing the Telephone Consumer Protection Act of 1991 Edison Electric Institute Petition for Declaratory Ruling.* CG Docket No. 02-278 (FCC, June 9, 2025), https://docs.fcc.gov/public/attachments/DA-25-496A1.pdf.

[61] *Id.,* at 4.

FCC ensured that the Telephone Consumer Protection Act and their implementing rules do not impede demand response communications that help ensure reliable utility services.

Developments and Issues in Demand Response

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

Arizona. On March 12, 2025, the Arizona Corporation Commission (Arizona Commission) issued an order approving Arizona Public Service Company's (APS) new bring-your-own-device (BYOD) battery pilot plan, which will provide compensation to participating APS customers for allowing their personal battery storage systems to be dispatched to provide aggregate demand response capacity.[62] Customers must agree to participate in up to 60 dispatch events per year, with each event lasting one to four hours between 4 p.m. and 10 p.m. between May 1 and October 31. Participating customers will be compensated with an annual $110/kW capacity payment based on seasonal average kW performance. The plan caps participation at 5,000 residential customers and requires pricing that does not shift costs to non-participating customers.

California. On April 14, 2025, the California Energy Commission adopted the fourth edition of its Demand Side Grid Support (DSGS) Program Guidelines.[63] The DSGS Program offers incentives to electric customers that provide load reduction and backup generation to support the state's electric grid during extreme events from May to October.[64] The fourth edition of the DSGS Program Guidelines makes several updates and clarifications regarding incentive options, eligibility, and participation requirements. Most notably, it creates a new option for participation in the DSGS Program, under which third-party load flexibility providers, publicly-owned electric utilities, and community choice aggregators are eligible to serve as load flexibility VPP aggregators. Load flexibility VPPs could consist of dispatchable HVAC equipment controlled by smart thermostats, electric water heaters, electric vehicle supply equipment, stationary behind-the-meter batteries, or residential smart electric panels. Flexibility VPPs must aggregate a minimum of 200 kW across all aggregations, 100 kW in at least one single aggregation, or 50 kW in at least 3 aggregations to be eligible to participate. Additionally, each participating site in a load flexibility VPP must not be registered to participate in CAISO wholesale demand response programs or be a distribution service customer of Pacific Gas and Electric Company.

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[62] *Application for Approval of New Bring-Your-Own-Device Battery Pilot Plan of Administration*, Docket No. E-01345A-22-0144, (Arizona Commission Mar. 12, 2025), https://docket.images.azcc.gov/0000213209.pdf?i=1750103440552.

[63] *Resolution Adopting the Demand Side Grid Support Program Guidelines, Fourth Edition*, Docket No. 22-RENEW-01, (CEC Apr. 14, 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=262675&DocumentContentId=99274.

[64] *See* CEC, *Demand Side Grid Support (DSGS) Program Guidelines, Fourth Edition* (Apr. 2025), https://efiling.energy.ca.gov/GetDocument.aspx?tn=262658.

Delaware. On July 16, 2025, the governor of Delaware signed a Delaware State Senate joint resolution directing the Delaware Sustainable Energy Utility[65] (DESEU) to study the costs and benefits of adopting energy storage systems, both in front of and behind the customer meter.[66] All electric public utilities in Delaware are required to participate in the study. The DESEU must work with the State Energy Office, the Delaware Public Service Commission, the Division of the Public Advocate, the University of Delaware, the electric public utilities in Delaware, and other interested stakeholders. The study will cover regulatory issues, the potential value of battery storage for demand reduction, the use of battery storage to avoid or defer investments in distribution and transmission infrastructure, and the incremental benefits of storage when paired with renewable energy systems. The study will also identify grid service value streams, including local peak demand reduction, resilience, and voltage stabilization. Additionally, the study will explore the best use and optimal siting of energy storage, land use and environmental impacts, community and legal issues, procurement and ownership frameworks, and participation incentives. The resolution also directs the DESEU to work with Delmarva Power & Light Company, the Delaware Municipal Electric Corporation, the Delaware Electric Cooperative, and one independent power producer to develop and deploy at least one pilot project involving battery storage systems. The pilot projects should focus on addressing grid challenges, such as peak load reduction, resilience, and hosting capacity improvements. The DESEU must publish a progress report on the study and pilots by December 31, 2025, and a comprehensive final report by June 1, 2026.

Maine. On April 23, 2025, the Maine Commission issued an order approving the Efficiency Maine Trust's Sixth Triennial Plan, which will be in effect from July 1, 2025, to June 30, 2028.[67] The plan aims to achieve annual savings of 148,000 MWh of electricity and a 45.6 MW reduction in summer peak demand from the Efficiency Maine Trust electricity programs.[68] Most relevant to this report, the plan will continue a demand response program to temporarily reduce the load of commercial and industrial customers at times of peak

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[65] The Delaware Sustainable Energy Utility (DESEU), also known as Energize Delaware, is a nonprofit organization offering programs and resources to help residents and businesses save money through clean energy and efficiency. It was created in 2007 by the state of Delaware to foster a sustainable energy future. *See* Energize Delaware, *About Us,* https://energizedelaware.org/about-us/.

[66] Delaware Sustainable Energy Utility Energy Storage Systems Study and Battery Storage Pilot Resolution, S.J.R. No. 3, 153rd Gen. Assemb. (2025) (Del.) (enacted), https://legis.delaware.gov/json/BillDetail/GenerateHtmlDocumentEngrossment?engrossmentId=37067&docTypeId=6.

[67] *Efficiency Maine Trust Request for Approval of the Triennial Plan for Fiscal Years 2026-2028*, Docket No. 2024-00310, (Maine Commission Apr. 25, 2025). https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={00476E96-0000-CE1A-921C-02405F5749AF}&DocExt=pdf&DocName=2024-000310%20ORDER%20on%20STIP%204.25.25%201.pdf.

[68] *Id.* at 3.

demand during the summer. Through the demand response program, program partners directly compensate participants based on their average kW reductions.[69]

Maryland. On February 4, 2025, the Maryland Public Service Commission (Maryland Commission) issued a notice[70] initiating a new docket and request for comments related to the implementation of VPPs and vehicle-to-grid services in Maryland to facilitate implementing FERC Order No. 2222[71] and the goals of the Maryland DRIVE Act[72]

On April 11, 2025, the Maryland Commission issued an order, directing investor-owned utilities and the Southern Maryland Electric Cooperative to submit reports on their distributed energy resource management system (DERMS) plans and conceptual reports on DER registration, device-level metering repositories, customer information sharing, and communications protocols within six months.[73] Additionally, the order requires Potomac Edison to file a conceptual report on non-AMI solutions to facilitate VPP implementation. Following the submission of the reports on October 11, 2025, the Maryland Commission held a technical conference on December 3, 2025, to consider stakeholder comments.[74]

Minnesota. On March 17, 2025, Xcel Energy filed a petition with the Minnesota Public Utilities Commission (Minnesota Commission) proposing to replace its Energy Action Days behavioral demand response program with a new Peak Time Rebate (PTR) program as part of its Energy Conservation and

[69] *See* Efficiency Maine, *Efficiency Maine Trust's Triennial Plan VI Approved* (April 2025), https://www.efficiencymaine.com/efficiency-maine-trusts-triennial-plan-vi-approved/. *See also* Efficiency Maine, *Demand Response Program Incentive Calculation Methodology* (May 2025), https://www.efficiencymaine.com/docs/Demand_Response_Incentive_Calculation_Methodology.pdf.

[70] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, Case No. 9778, (Maryland Commission Feb. 4, 2025) https://webpscxb.psc.state.md.us/DMS/case/9778.

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

[72] The Maryland DRIVE Act requires the Maryland Commission to adopt regulations to establish bidirectional EV charging programs allowing EVs to not only draw power from the grid, but also to supply electricity back. *See* DRIVE Act, H.B. 1256, 2024 Gen. Assemb. (2024) (Md) (enacted), https://mgaleg.maryland.gov/2024RS/Chapters_noln/CH_476_hb1256t.pdf.

[73] *Order on Implementation of FERC Order No. 2222 and Virtual Power Plants in Maryland*, Case No. 9778 at 31, (Maryland Commission Apr. 11, 2025) https://webpscxb.psc.state.md.us/DMS/case/9778.

[74] *Notice of Technical Conference and Request for Comments*, Case No. 9778, (Maryland Commission Oct. 14, 2025) https://webpscxb.psc.state.md.us/DMS/case/9778.

Optimization[75] portfolio.[76] This filing is to comply with orders from the Minnesota Commission directing Xcel Energy to propose procedural pathways for additional demand response and load flexibility programs and to evaluate a proposal for a peak-time rebate program for Xcel Energy.[77] Xcel proposes to work with the Minnesota Department of Commerce to implement and recover the costs for the PTR program through the Energy Conservation and Optimization process. Xcel Energy states that the PTR program would directly reward or rebate customers who respond.[78] Under the PTR program, customers would earn a rebate of $1/kWh reduction and receive a yearly rebate on their electric bill based on participation.[79] Xcel Energy plans to implement the program in 2026 and expects to enroll approximately 15,500 customers in the first year.[80]

On May 15, 2025, the Minnesota Commission issued an order accepting Xcel Energy's revised proposal of a time-of-use rate for residential customers.[81] Participation in the new time-of-use rate is voluntary, employing an opt-in approach, and establishes an on-peak period of 6:00 p.m. to 9:00 p.m.[82]

South Carolina. On May 12, 2025, the governor of South Carolina signed the "South Carolina Energy Security Act" into law, which includes provisions encouraging the expansion of DSM programs within the state.[83] The law declares that expanding utility investment and customer access to cost-effective DSM programs is in the public interest because it will result in more efficient use of existing resources, promote

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[75] Minnesota's Energy and Optimization Program is overseen by the Minnesota Department of Commerce and helps households and businesses use electricity and natural gas more efficiently. *See* Minnesota Commerce Department, *Energy Conservation and Optimization*, https://mn.gov/commerce/energy/conserving-energy/eco/.

[76] *Petition In the Matter of a Peak Time Rebate Program for Northern States Power Co. d/b/a Xcel Energy to Further the Commission's Advanced Rate Design Efforts in Docket No. E002/CI-24-115*, Docket No. E-002/M-24-432, (Minnesota Commission Mar. 17,2025) https://www.edockets.state.mn.us/documents/%7BB07CA595-0000-C51B-9544-BC6C5D999B7E%7D/download?contentSequence=0&rowIndex=11

[77] *Id.* at 1-2. (citing *Order Approving Transmission Cost Recovery Rider Revenue Requirement and Denying Performance Incentive Mechanisms*, Docket No. E002/M-23-467, (MN PUC Dec. 4, 2024); *Notice of and Order for Hearing*, Docket No. E002/GR-24-320, (Minnesota Commission Dec. 30, 2024)).

[78] *Id.* at 5.

[79] *Id.* at 9.

[80] *Id* at 12.

[81] *Order Approving Revised Opt-in Proposal and Setting Reporting Requirements*, Docket No. E-002/M-23-524, (Minnesota Commission May 15, 2025) https://www.edockets.state.mn.us/documents/%7B90D8D596-0000-C316-998D-0637F9661E8B%7D/download?contentSequence=0&rowIndex=3.

[82] *Id.* at 7.

[83] South Carolina Energy Security Act, H.B. 3309, 126th Gen. Assemb. (2025) (S.C.) (enacted),https://www.scstatehouse.gov/sess126_2025-2026/bills/3309.htm.

lower energy costs, mitigate the increasing need for new generation and associated resources, and assist customers in managing their electricity usage to better control their electric bill. Accordingly, the law directs the South Carolina Public Service Commission (SC Commission) to require utilities to plan and invest in all reasonable, prudent, and available demand-side resources that are cost-effective, energy efficient technologies. The law also requires utilities to submit an annual report regarding their DSM programs to the SC Commission and adds incentives for programs using customer-sited DERs.

Texas. On June 20, 2025, the governor of Texas signed a law directing the Texas Public Utility Commission (Texas Commission) to require ERCOT to develop a demand management service that enables mandatory curtailment of large loads, such as data centers, during firm load shed events.[84] The law applies to large load customers with a demand of at least 75 MW that interconnect to ERCOT on or after January 1, 2026. The law also calls on ERCOT to develop a reliability service to competitively procure demand reductions from large load customers to be deployed in the event of an anticipated emergency condition. In developing this service, the law states that ERCOT must (1) specify the periods when the service may be used to maintain reliability during extreme weather events; (2) provide at least 24 hours' advance notice before initiating a curtailment event and require large load customers to remain curtailed for the duration of the energy emergency alert event or until the load is recalled; and (3) prohibit participation by large load customers that curtail in response to wholesale electricity prices or that participate in other reliability or ancillary services.

On the same day, the governor of Texas also signed a law creating the Texas Energy Waste Advisory Committee to make recommendations for coordinating and improving state agency and interagency programs that reduce energy waste, increase energy efficiency, and enhance demand response programs in order to increase reliability of electric service in ERCOT.[85]

Virginia. On May 2, 2025, the governor of Virginia signed a law directing Dominion Energy to launch a VPP pilot program.[86] Specifically, the law requires that Dominion Energy petition the Virginia State Corporation Commission (Virginia Commission) to conduct a pilot program to evaluate methods to optimize demand through various technology applications including the establishment of VPPs by December 2025. The law requires that the pilot program evaluate grid capacity needs as well as the ability of VPPs to provide grid services, such as peak-shaving, during times of peak demand. It also stipulates that the pilot program consist of DER aggregations totaling up to 450 MW from resources in multiple geographic regions of the state. In conducting the pilot program, the law requires the utility to evaluate methods to holistically optimize demand, including by reviewing enrollment and performance incentives for participants; incentives for purchasing battery storage devices; operational parameters for grid services; mechanisms for disenrollment for nonperforming participants; and development of a preliminary program

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[84] An Act Relating to Electricity Planning, Interconnection, Operation, and Service Costs for Large Loads, S.B. 6, 89th Leg., Reg. Sess. (2025) (Tex.) (enacted), https://capitol.texas.gov/tlodocs/89R/billtext/pdf/SB00006F.pdf#navpanes=0.

[85] Texas Energy Waste Advisory Committee Act, H.B. 5323, 89th Leg., Reg. Sess. (2025) (Tex.) (enacted), https://capitol.texas.gov/tlodocs/89R/billtext/html/HB05323F.htm.

[86] Community Energy Act, S.B. 1100, 2025 Gen. Assemb. (2025) (Va.) (enacted), https://lis.blob.core.windows.net/files/1079987.PDF.

tariff. The utility has until November 15, 2026, to petition the Virginia Commission for a program tariff to allow residential, commercial, and industrial customers to enroll directly or through an aggregator. The pilot program will end by July 1, 2028, after which the Virginia Commission will review the results and evaluate the pilot program's effectiveness in providing grid services during times of peak demand. On September 15, 2025, Dominion Energy initiated a stakeholder process to help develop the VPP program and solicited stakeholder feedback through the end of October 2025.[87] On December 1, 2025, Dominion Energy submitted its proposed VPP pilot program to the Virginia Commission.[88]

[87] Dominion Energy, *Virtual Power Plant*, https://www.dominionenergy.com/virginia/save-energy/virtual-power-plant.

[88] *Application of Virginia Electric and Power Company for approval of its Virtual Plant Pilot Program under §56:585.1:16 of the Code of Virginia*, Docket No. PUR-2025-00211, (Virginia Commission Dec. 1, 2025) https://www.scc.virginia.gov/docketsearch/DOCS/89hy01!.PDF.

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

Electric load growth resulting from the electrification of buildings, manufacturing, and transportation, as well as from data centers, is driving state regulators and decision-makers to develop solutions that can manage these loads to cost-effectively meet power system needs. They continue to evaluate demand response, peak reduction, and critical peak pricing programs as tools to provide demand flexibility and improve system reliability. This chapter discusses barriers that may be limiting customer participation in such programs and efforts to address them.

Implementing Time-varying Rates

Evidence suggests that the lack of advanced meters may no longer be a primary barrier to participation in dynamic pricing programs. While enrollment in retail dynamic pricing programs in the United States continues to grow (see Chapter 5: Developments and Issues in Demand Response), according to EIA data, only roughly 11% of all electric customers are enrolled in a dynamic pricing program, which is relatively low compared to the penetration rate of advanced meters at 76.8%.[89]

Resources for the Future published a working paper that presented a synthesis of literature that examines the factors influencing customer responsiveness to time-based electricity rates.[90] The working paper found that providing control technologies, such as programmable thermostats, improves the effectiveness of time-based rate designs in reducing peak demand. In addition, event-based rates, such as critical peak pricing and peak-time rebates, lead to greater peak demand reductions compared to time-of-use rates. While the working paper does not suggest a solution, it appears that several factors affect, and may be barriers to, customer enrollment in time-varying rate programs.

As detailed in previous years' Assessments of Demand Response and Advanced Metering, state regulators continue to examine how to optimize time-varying rate design to maximize grid value while accommodating evolving customer needs and creating incentives for customers to use time-varying rates. For example, the Maine Commission initiated an inquiry to consider the implementation of time-of-use rates for customers of the state's IOUs.[91] The inquiry focuses on rate design issues such as time-of-use time periods; whether the

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[89] Sources: 2023 Form EIA-861 Dynamic_Pricing_2023, 2023 Form EIA-861 Sales_Ult_Cust_2023, and 2023 Form EIA-861 Advanced_Meters_2023 data files.

[90] Resources for the Future, *Different Prices for Different Slices: A Meta-Analysis of Time-Based Electricity Rates* at 3, (March 13, 2025), https://www.rff.org/publications/working-papers/different-prices-for-different-slices-a-meta-analysis-of-time-based-electricity-rates/

[91] *Inquiry of Time of Use Rates for Delivery and Standard Offer,* Docket No. 2024-00231 (Maine Commission, Aug. 28, 2024). https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=125184&CaseNumber=2024-00231.

time-of-use rate should be opt-in, out-out, or mandatory; the interaction with other rates offered by utilities; the effect that expected changes in seasonal load variability will have on demand response; and lessons learned from other jurisdictions.[92] The inquiry will also address customer education on time-of-use rates and modeling and monitoring the pricing of such rates.

Opportunities for Data Center Demand Response Participation

While technical requirements may constitute a barrier to some data centers serving as flexible loads, there is potential flexibility that may allow certain large loads to participate in demand response, peak reduction, or other critical peak pricing programs. For example, state decision-makers and utilities can allow data centers to participate in demand response and other peak reduction programs where possible. As discussed in Chapter 5, Texas enacted legislation directing ERCOT to develop a demand management service that enables mandatory curtailment of large loads, such as data centers, during firm load shed events (see Chapter 5: Developments and Issues in Demand Response). Recently, Google entered agreements with Indiana Michigan Power and the Tennessee Valley Authority for Google to provide demand response from its data centers.[93] Google will target machine learning workloads at the data centers to reduce its power demand. In addition, the U.S. Department of Energy's Secretary of Energy Advisory Board Working Group on Powering AI and Data Center Infrastructure explored options for supporting data center power demands, in a report issued in July 2024.[94] Among other topics, the report examined secure operational frameworks that allow data centers to optimize their energy consumption, contribute to grid peak load management, and provide other grid services. The report makes recommendations in several areas and includes a proposed taxonomy of concepts to characterize flexibility needs of the grid and to explore opportunities for data centers to participate.

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[92] *Id.* at 5-6.

[93] Google, *How We're Making Data Centers More Flexible to Benefit Power grids* (Aug. 2025), https://blog.google/inside-google/infrastructure/how-were-making-data-centers-more-flexible-to-benefit-power-grids/.

[94] DOE, *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure* at 3, 6 (July 2024), https://www.energy.gov/sites/default/files/2024-08/Powering%20AI%20and%20Data%20Center%20Infrastructure%20Recommendations%20July%202024.pdf.

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

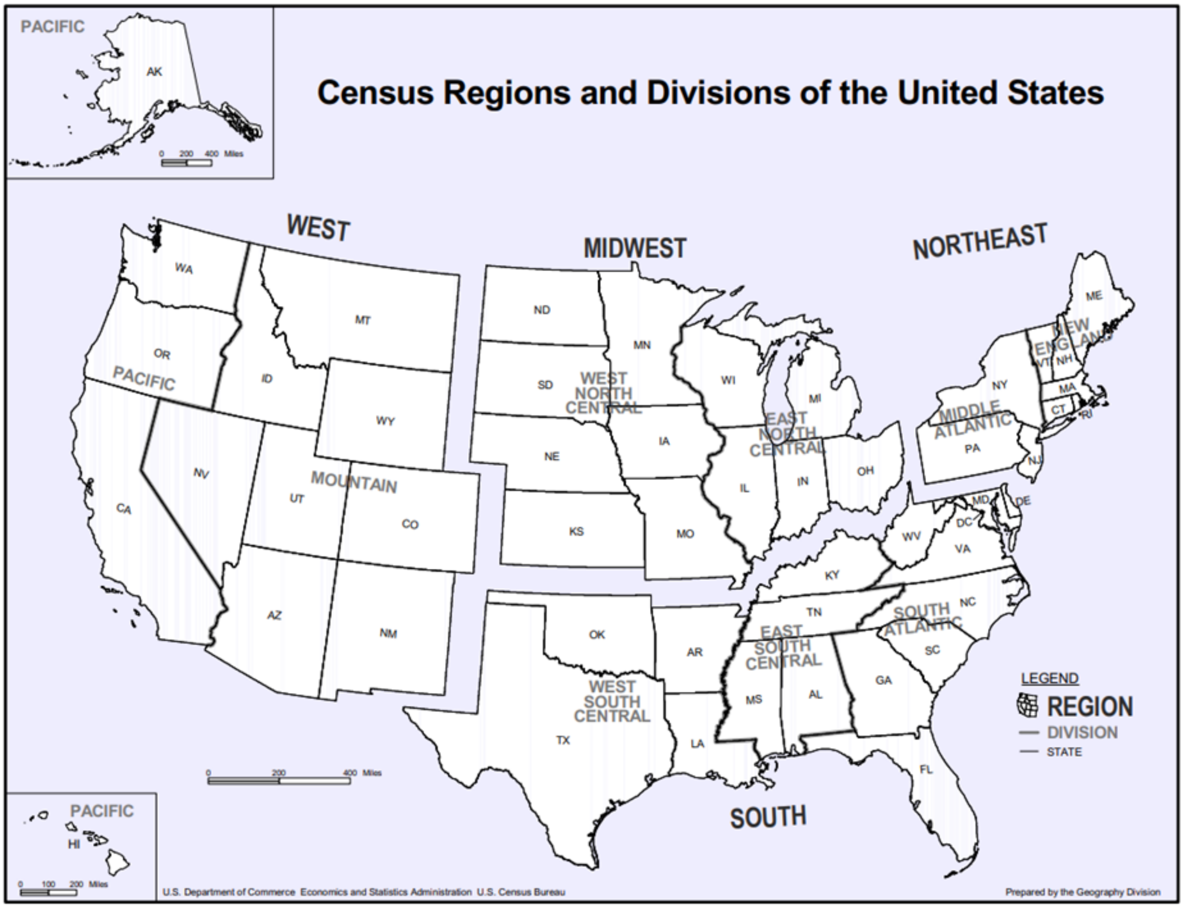
Division 5, South Atlantic: Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, West Virginia

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


Census Regions and Divisions of the United States
PACIFIC
AK
WEST
MIDWEST
NORTHEAST
SOUTH
PACIFIC
MOUNTAIN
WEST NORTH CENTRAL
EAST NORTH CENTRAL
NEW ENGLAND
MIDDLE ATLANTIC
SOUTH ATLANTIC
EAST SOUTH CENTRAL
WEST SOUTH CENTRAL
WA
OR
CA
NV
ID
MT
WY
UT
CO
AZ
NM
ND
SD
NE
KS
MN
IA
MO
WI
IL
MI
IN
OH
OK
TX
AR
LA
KY
TN
MS
AL
GA
FL
SC
NC
VA
WV
MD
DC
DE
NJ
PA
NY
CT
RI
MA
VT
NH
ME
PACIFIC
HI
LEGEND
REGION
DIVISION
STATE
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 – 2023)

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%
2023 Form EIA-861[1]	Dec 2023 (EIA)	128.4	167.2	76.8%

Sources: [1]FERC, *Assessment of Demand Response and Advanced Metering* 2008-2012. [2]EIA-861 Advanced Metering data files 2011-2023. [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.

Appendix III: List of Acronyms

AI: Artificial intelligence

AMI: Advanced metering infrastructure

AMF: Advanced metering functionality

AMR: Automated meter reading

APS: Arizona Public Service Company

BGE: Baltimore Gas & Electric

BYOD: Bring your own device

CAISO: California Independent System Operator

CEC: California Energy Commission

CPCN: Certificate of public convenience and necessity

DER(s): Distributed energy resource(s)

DESEU: Delaware Sustainable Energy Utility

DOE: Department of Energy

DSGS Program: CEC Demand Side Grid Support Program

DSM: Demand-side management

EIA: Energy Information Administration

ECRS: ERCOT Contingency Reserve Service

ELR: PJM Economic Load Response

EPAct 2005: Energy Policy Act of 2005

ERCOT: Electric Reliability Council of Texas

FCC: Federal Communications Commission

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

GWh: Gigawatt-hour

HVAC: Heating, ventilation, and air conditioning

IEI: Edison Foundation Institute for Electrical Innovation

IOU: Investor-owned utility

ISO(s): Independent System Operator(s)

ISO-NE: ISO New England

LIPA: Long Island Power Authority

LMR(s): MISO Load-Modifying Resource(s)

MISO: Midcontinent Independent System Operator

MW: Megawatt

NOPR: Notice of Proposed Rulemaking

NYISO: New York Independent System Operator

NYSERDA: New York State Energy Research and Development Authority

PJM: PJM Interconnection

PTR: Xcel Peak Time Rebate program

RAA: PJM Reliability Assurance Agreement Among Load Serving Entities

RRS: ERCOT Responsive Reserve Service

RTO(s): Regional Transmission Organization(s)

SPP: Southwest Power Pool

VPP(s): Virtual power plant(s)