50 STATES OF

VIRTUAL POWER PLANTS & SUPPORTING DISTRIBUTED ENERGY RESOURCES

2024 State Policy Snapshot

NC CLEAN ENERGY TECHNOLOGY CENTER

Smart Electric Power Alliance

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About This Report

The NC Clean Energy Technology Center and the Smart Electric Power Alliance have compiled all the information contained within this *50 States of Virtual Power Plant and Supporting Distributed Energy Resources: 2024 State Policy Snapshot* report from publicly-available data sources, but the categorizations, characterizations, and summaries are our own.

If you found the information helpful or if you would like to learn more about the methodology and underlying data, please let us know; as of the time of publication, February 2025, we are considering more periodic updates to this report and additional data sets and information related to the topics herein, and we appreciate your feedback. To alert us to new or missing data or a possible correction, please email Autumn Proudlove (afproudl@ncsu.edu) and Lakin Garth (lgarth@sepapower.org).

About The North Carolina Clean Energy Technology Center

The NC Clean Energy Technology Center (NCCETC) is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating, and supporting clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

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The NC Clean Energy Technology Center also publishes the 50 States of Solar, the 50 States of Grid Modernization, the 50 States of Electric Vehicles, and the 50 States of Power Decarbonization on a quarterly basis. Executive summaries of these reports may be found here.

SEPA produces research and reports related to its focus areas, including virtual power plants and supporting DERs. Our research and reports may be found here.

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Glossary of Abbreviations

ADER	Aggregated Distributed Energy Resource
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
BYOD	Bring Your Own Device
BYOT	Bring Your Own Thermostat
C&I	Commercial & Industrial
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DR	Demand Response
DSM	Demand-Side Management
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
HVAC	Heating, Ventilation, and Air Conditioning
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
LMI	Low to Moderate Income
MW	Megawatt
RFI	Request for Information

RFP	Request for Proposal
RTO	Regional Transmission Organization
T&D	Transmission and Distribution
TEP	Transportation Electrification Plan or Portfolio
TOU	Time-of-Use
VPP	Virtual Power Plant
V2G	Vehicle-to-Grid

Introduction

The North Carolina Clean Energy Technology Center (NCCETC), in partnership with the Smart Electric Power Alliance (SEPA), is pleased to present the *50 States of Virtual Power Plant and Supporting Distributed Energy Resources: 2024 State Policy Snapshot.* This first-of-its-kind report provides an overview and insights on state regulatory and legislative actions related to virtual power plants (VPPs) and distributed energy resource (DER) aggregations. We created this report to help our collective audience understand the breadth and scope of policy actions related to VPPs and DER aggregations in the United States.

By focusing on state-level actions, our intent is to develop a more complete understanding of the VPP and DER aggregation policy landscape and to begin to document the range and growth of policy activity. Specifically, this report considers regulatory and legislative actions in 2024 and those expected to occur in 2025 as of the time of writing (January 2025). We hope this is a useful resource for utilities, regulators, utility service providers, researchers, and other interested parties.

What is a Virtual Power Plant?

The U.S. Department of Energy (DOE) recently defined VPPs as "aggregations of distributed energy resources (DERs) that can balance electrical loads and provide utility-scale and utility-grade grid services like a traditional power plant."[1] This 2024 Snapshot takes a similarly, holistic approach in defining the types of DERs used in VPPs, including, but not solely limited to, smart thermostats, electric water heaters, EVs and EV chargers (bi-directional or not), behind-the-meter battery storage (with or without rooftop solar PV), and curtailable commercial, industrial, and agricultural loads.

While DERs and the concept of DER aggregation have been part of the electric utility landscape for years, recent technological advancements amidst forecasted increases in electricity demand have thrust them into a central role in the clean energy transition. Compared with utility-scale renewables such as solar and wind, these resources do not require the investment and build-out of additional transmission capacity and may not require significant distribution system investments. Furthermore, DER interconnection to the distribution grid is also typically less time-consuming and less expensive than interconnecting larger, utility-scale renewables at the transmission level, while also holding the potential to enhance reliability, cost savings, dispatchability, and flexibility.

[1] U.S. Department of Energy (S2023). Pathways to Commercial Liftoff: Virtual Power Plants.

What are the Different Types of VPP Models?

Several factors, including state policy and regulatory frameworks, shape VPP participation models and structures. In the United States, four distinct models are emerging:

- Direct VPP participation in wholesale electricity markets
- Third party-operated VPP via contract with a utility
- Utility-led VPP utilizing third-party platform
- Utility-owned and operated VPP

The diversity of these participation models means that VPP actions can vary significantly across the states and the different types of DERs involved.

Executive Summary

The 2024 Snapshot includes actions related to the following types of programs: (1) behind-the-meter battery storage and multi-technology VPP programs, (2) electric vehicle (EV) active managed charging programs, and (3) demand response programs utilizing direct device control or automation. It excludes actions related to rate design, “passive” EV-managed charging programs, and demand response programs focused on manual customer response. The report addresses actions involving individual IOU programs; it does not include actions related to electric cooperatives or municipal utility programs.

A total of 105 state and investor-owned utility (IOU) actions related to VPPs were taken across 38 states and the District of Columbia (D.C.) in 2024. The most prevalent types of actions pertained to individual VPP, demand response, or active managed charging programs implemented by states or utilities. This report's *Overview of 2024 VPP Activity* section provides additional details on these actions.

The 2024 Snapshot captures the following actions related to these programs or policy types:

- **Utility Program** - A program aggregating or actively managing customer-sited DERs that is led by an individual utility and only available to that utility's customers.
- **State Program** - A program aggregating or actively managing customer-sited DERs that is available statewide.
- **State Rules** - Rules adopted by state legislators or regulators governing state or utility DER aggregation programs.
- **State Target** - A requirement established by state legislators or regulators for utilities to procure a certain amount of capacity that is associated with aggregated DERs.
- **Utility Target** - A utility-set goal to procure a certain amount of capacity that is associated with aggregated DERs.
- **Procurement** - A competitive solicitation, or rules governing competitive solicitations, of aggregated DERs.
- **Wholesale Market Participation** - Rules governing the ability of aggregated DERs to participate in wholesale electricity markets.
- **Investigation** - A proceeding or other effort focused on gathering information and stakeholder feedback on DER aggregation where a specific policy proposal is not yet under consideration.

There were four trends in VPP actions in 2024: (1) utilities driving VPP activity and expanding programs, (2) state policymakers and regulators developing statewide frameworks for VPPs, (3) states initiating investigations into VPPs, and (4) states considering net metering program interactions.

Some of the most notable VPP actions of 2024 are highlighted and assessed in more detail:

- **Colorado**: The Modernize Energy Distribution Act
- **Maryland**: Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act
- **Minnesota**: Xcel Energy's Distributed Capacity Procurement (DCP) Announcement
- **North Carolina**: Duke Energy's PowerPair Program
- **Washington**: Demand Response and Flexibility Target for Large Combination Utilities

Many state-level policy actions related to VPPs and supporting DERs in 2024 remain ongoing and have led to expected activity in 2025, which we cover in the *2025 VPP Activity Outlook* section of this 2024 Snapshot. The final section of the 2024 Snapshot report – *2024 VPP Actions by State* – includes a detailed list of actions by state.

Overview of 2024 VPP Activity

Table 1 summarizes state and IOU actions related to VPPs during 2024. Of the 105 actions identified, the most common were related to state and utility energy storage or multi-technology VPP programs (31), state or utility demand response programs (25), and state or utility managed charging programs for EVs (16). These actions occurred across 38 states and D.C. (Figure 1).

Table 1. 2024 Summary of State and Utility VPP Actions

Action Type	# of Actions	% by Type	# of States
State or Utility Storage or Multi-Technology Program	31	30%	20 + D.C.
State or Utility Demand Response Program	25	24%	15
State or Utility Managed Charging Program	16	15%	15
State VPP Rules	15	14%	10
Wholesale Market Participation	7	7%	6
Investigation	5	5%	5
State or Utility Target	4	4%	3
Procurement	2	2%	2
Total	**105**	**100%**	**38 States + D.C.**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 1. 2024 State and Utility VPP Activity

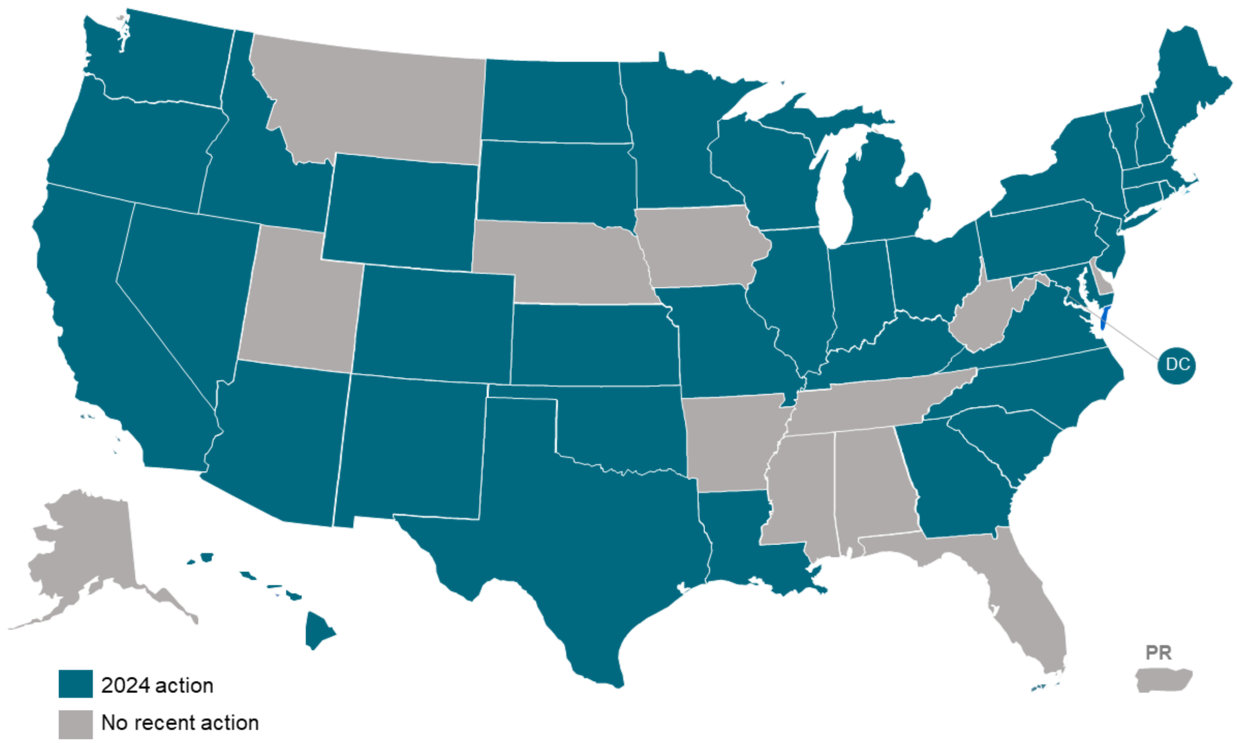


Figure 2. 2024 State and Utility VPP Activity, by Number of Actions

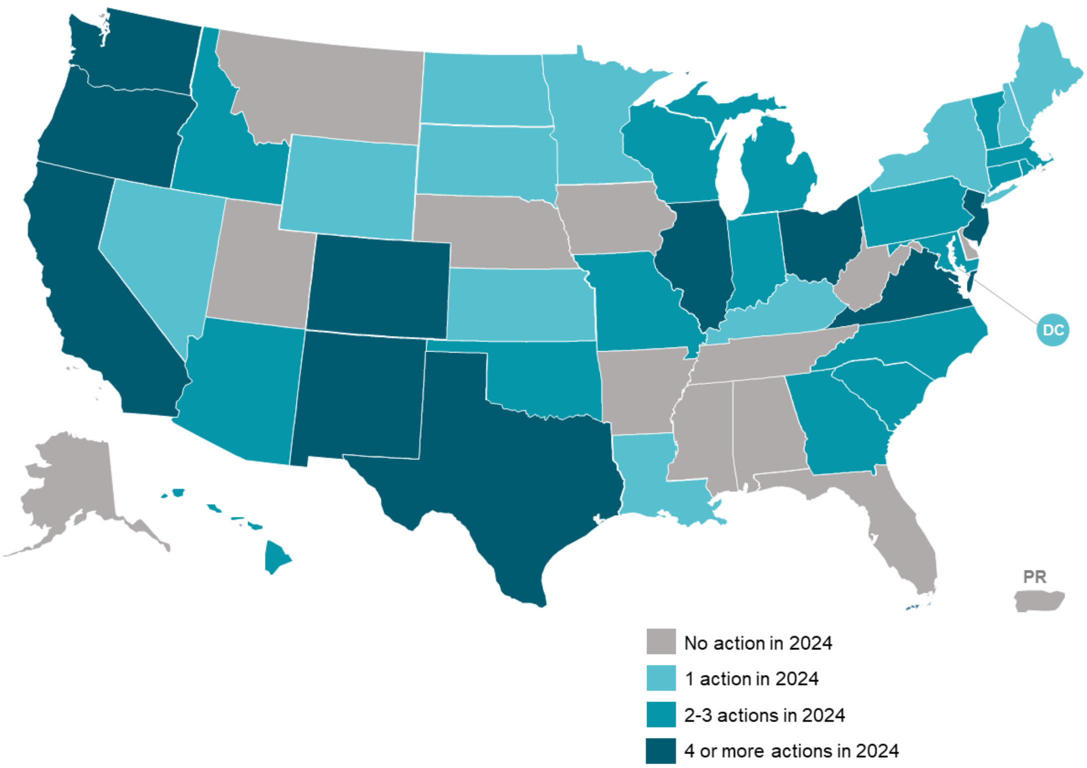
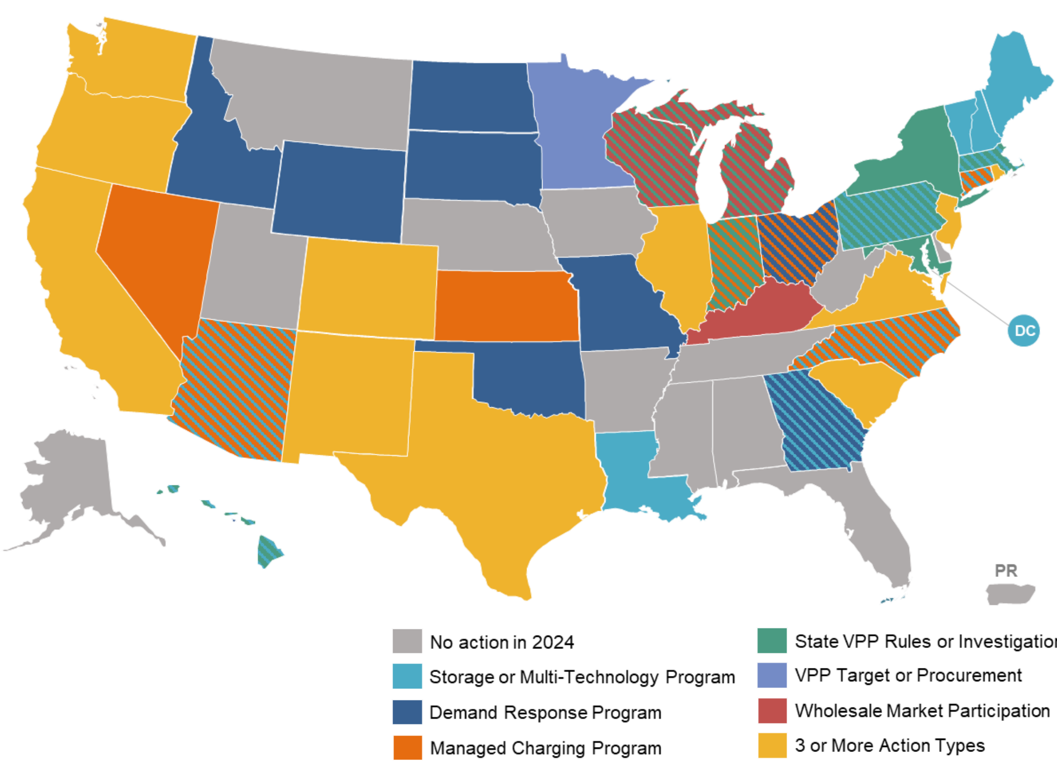


Figure 3. 2024 State and Utility VPP Activity, by Type of Action



Notable 2024 VPP Policy Actions

Several innovative or impactful 2024 VPP actions merit special attention in this Snapshot. These are noted below. In addition, the *2024 VPP Actions by State* section of this report provides more detailed information about these actions, including links to relevant regulatory dockets and decisions and legislation.

Colorado: The Modernize Energy Distribution Act

The Modernize Energy Distribution Act (Powering Colorado), or S.B. 218, enacted in May 2024, requires Xcel Energy to propose – by **February 1, 2025**, for review by the Colorado Public Utilities Commission – VPP programs and a tariff for performance-based compensation. These programs should allow customer and DER aggregator participation and Xcel Energy may participate as a DER aggregator. The compensation structure should be based on local and system peak demand reduction, clean peak services, voltage support and other ancillary services, avoided cost of T&D upgrades or capacity expansion, locational value, use of telemetry, and other functions the Commission so chooses. Among other requirements, the law also requires Xcel Energy to identify interconnection and load hosting capacity for DERs in disproportionately impacted communities.

Maryland: Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act

H.B. 1256 and S.B. 959, enacted in April 2024 and known together as the DRIVE Act, direct the Maryland Public Service Commission to develop a program for all IOUs to establish pilot or temporary programs to compensate DER owners and aggregators for distribution system support services on a pay-for-performance basis. The law sets the timeline for the Commission to make the program available as of January 1, 2025, and for IOUs to file tariffs for Commission approval by **July 1, 2025**. As part of its proceeding implementing the DRIVE Act, the Commission issued an order in October 2024 authorizing, but not mandating, IOUs to offer incentives for renewable on-site generation. The Commission also took steps to develop licensing requirements for DER aggregators.

Minnesota: Xcel Energy Distributed Capacity Procurement Announcement

In February 2024, Xcel Energy filed its 2024-2040 Upper Midwest Resource Plan for its territories in Minnesota, Wisconsin, Michigan, South Dakota, and North Dakota. As part of the resource plan proceeding, Xcel Energy filed comments in August 2024 proposing a DCP process to integrate DERs into its plan. The program could procure anywhere from 400 MW to over 1 GW from DERs, depending on the system's needs. With a theoretical target of 400 MW of storage and 440 MW of solar, the DCP could launch within 9-12 months and deploy within 36 months. Xcel noted that this is not a formal proposal, adding that it would file a formal application in a separate proceeding in

2025. Xcel Energy filed a joint settlement agreement in October 2024, in which Xcel Energy committed to file the DCP proposal by **October 2025**. The settlement agreement remains pending as of late January 2025.

North Carolina: Duke Energy PowerPair Program

In January 2024, the North Carolina Utilities Commission approved Duke Energy's PowerPair program proposal – but with a larger incentive as recommended by the Public Staff. The program includes incentives of $0.36/W-AC for solar and $500/kWh for battery storage systems, with program participation capped at 30 MW each for Duke Energy Carolinas and Duke Energy Progress. The program targets two groups of participants: Cohort A will be served under the utility's recently approved net metering tariffs and will have complete control over their energy storage device, while Cohort B will be served under the bridge rate (a transitional net metering tariff) and will grant full control of their energy storage device to the utility. Later, in 2024, as part of an order on Duke Energy's Carbon Plan/Integrated Resource Plan, the Commission directed the utility to work with stakeholders to develop a non-residential version of its PowerPair program and to file such proposal by **September 2025**.

Washington: Demand Response and Flexibility Target for Large Combination Utilities

H.B. 1589, enacted in March 2024, requires a large combination gas and electric utilities to achieve annual demand response and demand flexibility equal to at least 10% of winter and summer peak electric demand by January 1, 2027. The Washington Utilities and Transportation Commission may require a higher target if it is determined to be cost-effective. The Commission may also accept lower-level achievement if it determines that this requirement is neither technically nor commercially feasible during the applicable emissions reduction period.

This legislation effectively applies only to Puget Sound Energy (PSE), which announced in late 2023 the expansion of its VPP program to dispatch sufficient electric capacity to mitigate summer and winter system peaks. In 2024, PSE's Flex program expanded to include battery storage and managed EV charging. The Commission currently has a rulemaking proceeding open to implement the legislation. The Commission Staff is accepting comments on its most recent draft rules implementing these provisions by **February 20, 2025**.

Top VPP Trends of 2024

As a growing number of states and utilities take steps to consider or advance VPPs, several trends are emerging across the United States. This section discusses four trends in VPP activity that emerged in 2024.

Utilities Driving VPP Activity and Expanding Programs

In 2024, VPP activity primarily centered around utility-proposed programs. Of the 105 actions tracked in this report, 68 pertained to utility programs of some type. The majority of these focused on energy storage or multi-technology programs, followed by demand response programs and managed charging programs. Many utility-led VPP programs initially began with bring-your-own smart thermostat (BYOT) programs; in several cases, utilities have expanded these programs to include more customer-sited resources with grid export capabilities, including battery storage, both with and without distributed solar PV.

Utilities that expanded their VPP offerings to include battery storage programs or pilots in 2024 include Arizona Public Service, Dominion Energy Virginia, Duke Energy (North Carolina), Public Service Electric & Gas New Jersey, and Puget Sound Energy. This trend took root in 2023 and 2024, and we expect it will continue in 2025, as noted by several examples in the *2025 VPP Activity Outlook* section of this report.

Statewide Framework Development for VPP Programs

In addition to utilities diversifying VPP offerings with additional technologies, policymakers and regulators in some states began developing statewide frameworks for VPP programs in 2024. For example, in Maryland, a new law directed the Public Service Commission to establish rules for VPP pilot programs, with utilities proposing programs by July 2025. In October 2024, the Commission issued an order allowing, but not mandating, utilities to offer incentives for distributed renewable assets. Any program a utility proposes must include low-income households as part of the program design.

Similarly, Colorado enacted legislation directing Xcel Energy to propose VPP programs and establish requirements for such programs. Prior to the enactment of this legislation, the Colorado Public Utilities Commission issued a decision with guidelines for VPP programs and procurement. The new law will supersede the Commission’s decision. In Pennsylvania, the Public Utility Commission issued an advanced notice of proposed rulemaking regarding DER aggregation in order to consider amendments or additions to existing Commission regulations and policy statements that may be warranted. Some states, including Illinois and Michigan, also considered legislation to adopt statewide VPP frameworks, but these bills were unsuccessful during 2024; it is expected that proposed legislation on VPPs will increase during 2025.

States Initiating Investigations

Several states initiated investigations related to VPPs, largely to gather information related to the implementation of FERC Order No. 2222 (Order 2222) – the goal of which was to enable DERs to participate in the wholesale markets run by regional grid operators – or the development of a statewide VPP framework. In New Jersey, the Board of Public Utilities invited feedback from IOUs and other parties interested in wholesale market participation of DER aggregations under Order 2222. Meanwhile, the Michigan Public Service Commission's demand response aggregation workgroup met throughout 2024 to discuss a variety of issues related to VPPs.

In Wisconsin, regulators opened a new proceeding to investigate distributed aggregation of retail customer resources. In New York, the Public Service Commission opened a "Grid of the Future" proceeding to help achieve the state's renewable energy goals through flexible resources. The first part of this proceeding will entail the Department of Public Service Staff performing a grid study to estimate the current and future potential capabilities of flexible resources across New York's grid.

States Considering Net Metering Program Interactions

Several states considered the interaction of VPP programs with other DER compensation programs, including net metering, in 2024. In Kentucky, Duke Energy's proposal for a net metering successor tariff included a provision prohibiting customers from entering into DER aggregator arrangements for participation in wholesale markets. Virginia also addressed this issue, enacting legislation clarifying that customer generators may participate in demand response, energy efficiency, or peak reduction from the dispatch of on-site battery storage as long as the compensation received is in exchange for a distinct service that does not already receive compensation through net metering.

Other states, including Hawaii and North Carolina, developed new VPP program offerings as a part of net metering successor tariff efforts. In Hawaii, Hawaiian Electric's (HECO) BYOD tariff offers DER tariff participants an opportunity to earn additional compensation for providing grid services. Similarly, in North Carolina, Duke Energy's new PowerPair program is an optional tariff that net metering successor tariff in which participants receive additional compensation.

2025 VPP Activity Outlook

Based on our review of VPP policy actions in 2024, we anticipate that several policy actions will continue in 2025. The following section summarizes key anticipated VPP activity for 11 selected states in 2025. Although this is not a complete summary of anticipated activity, this section highlights the authors' expectations about key actions in specific states based on our 2024 research.

The types of actions listed below include:

- **Program Updates** (California, Connecticut, Hawaii, North Carolina)
- **Program Proposals Filed** (Colorado, Minnesota)
- **Pilot Program Proposals Filed** (Georgia, Illinois, Maryland)
- **Investigation** (New York)
- **Wholesale Market Participation** (Texas)

California

Program Update – In October 2024, the California Energy Commission (CEC) staff released for public comment initial proposed draft modifications to the state's Demand Side Grid Support (DSGS) Guidelines for implementation starting with the 2025 program season. Proposed updates include:

- Refine Incentive Option 3: Market-Aware Storage Virtual Power Plant (VPP)
  - Increase minimum nominal aggregate power rating from 100 kW to 500 kW.
  - Allow dual participation with market-integrated demand response for exports only.
  - Apply a "residential" baseline to all batteries.
  - Clarify providers serving as VPP aggregators can enroll partner companies' aggregations as separate VPPs.
  - Shift to statewide test events for August, September, and October.
  - Add day-of Energy Emergency Alert (EEA) triggers for bonus compensation.
- Add New Incentive Option 4: Emergency Load Flex VPP
  - Eligible equipment: smart thermostats and electric water heaters.
  - Program trigger: EEA Watch+ (to address sudden onset emergencies).
  - Require upfront monthly capacity commitment.
  - Compensation structure: monthly capacity payment, adjusted for performance + potential "penalty" (incentive clawback) for large shortfall.
  - Event limits: minimum two events per season, maximum 60 hours per season.
  - Test events called by CEC in the absence of EEA events.
  - Measurement and verification based on device-specific data.

Commission staff released draft modifications to the DSGS Program Guidelines v4 in January 2025, with comments due **January 28, 2025**.

Colorado

Program Proposal Filing – S.B. 218 requires Xcel Energy to propose – by **February 1, 2025**, for review by the Colorado Public Utilities Commission – VPP programs and a tariff for performance-based compensation. The program should allow customer and DER aggregator participation; Xcel Energy may participate as a DER aggregator. The compensation structure should be based on local and system peak demand reduction, clean peak service, voltage support, and other ancillary services, avoided cost of T&D upgrades or capacity expansion, locational value, use of telemetry, and other functions the Commission chooses.

Connecticut

Program Update – In December 2024, the Connecticut Public Utilities Regulatory Authority (PURA) issued a decision addressing the Energy Storage Solutions program, which revises the formulas used to calculate event performance and the upfront incentive clawback so customers (residential, commercial, or industrial) enrolled in the program are proportionately penalized for underperformance of DERs during peak events. This replaces a flat fee penalty. Underperforming participants will no longer be removed from the program after two fee violations and will instead be subject to additional clawback fees. The program administrator can no longer waive clawback fees; waivers must obtain PURA approval.

The program administrator must submit a proposal by **May 1, 2025**, in order to change the upfront incentive model to a performance-based incentive model. The incentive would only be disbursed after reaching certain passive dispatch performance milestones. The passive dispatch window would be reduced from 3 p.m. - 8 p.m. to 5 p.m. - 8 p.m. Utilities would be authorized to hold “test” dispatch events in March and April to prepare for the summer season.

Georgia

Pilot Program Proposal Filing – As part of its 2023 integrated resource plan (IRP) update stipulation, Georgia Power will evaluate and develop a residential and small commercial solar and battery pilot program as part of its 2025 IRP. The utility will also continue to investigate DER and grid-enhancing technological opportunities; additional behind-the-meter operations for demand-side management (DSM), DERs, and storage. Georgia Power filed its 2025 IRP on **January 31, 2025**.

Hawaii

Program Update – The Hawaii Public Utilities Commission issued an order on December 31, 2024, initiating Phase 4 of a proceeding to review and evaluate modifications to HECO’s BYOD program. The Commission conceded that the BYOD is unpopular and does not add significant resources to the electric system. It further acknowledged that in order for the program to succeed, compensation provided for grid services must be greater than the benefits of self-consumption. The Commission pointed to the Massachusetts ConnectedSolutions program as a possible model for a revised program and requested comments from participants regarding that program. Initial comments were due **January 27, 2025**, and a technical conference was scheduled for **January 30, 2025**.

Illinois

Ameren Illinois

Pilot Program Proposal Filing – In December 2024, the Illinois Commerce Commission approved Ameren Illinois' refiled multi-year grid plan for 2024-2027. Ameren's plan included a proposal for new VPP programs. The processes for developing a VPP pilot program were approved. Ameren proposed to initiate workshops with interested parties to develop VPP and CS+S programs, commencing approximately four months after the resolution of the docket. Ameren committed to engaging on program-specific topics with workshop stakeholders, including agreeing on a value for compensation. Workshops likely will begin after **May 1, 2025**.

Ameren Illinois stated that if a consensus program is not determined within the 120-day engagement period, it will propose a program for Commission approval within 60 days of the workshop's conclusion. The Commission approved this process.

Commonwealth Edison

Pilot Program Proposal Filing – In December 2024, the Illinois Commerce Commission approved Commonwealth Edison's (ComEd's) refiled multi-year grid plan (2024-2027). ComEd's plan includes a proposal for new VPP programs. Commission Staff will host workshops regarding the proposed VPP programs in 2025.

The Commission directed workshop stakeholders to focus on: (1) customer eligibility, (2) compensation frameworks, (3) penalties for non-performance, and (4) event durations and notice requirements. Workshops will commence on an expedited schedule that will facilitate a tariff filing for the VPP programs within 180 days of the Commission's order in this proceeding. Based on the order's timeline, a tariff filing would be expected by **June 17, 2025.**

Maryland

Pilot Program Proposal Filing – Under 2024's DRIVE Act, all Maryland IOUs (Baltimore Gas & Electric, Delmarva Power & Light, Potomac Electric Power, and Potomac Edison) must file to establish pilot or temporary programs to compensate DER owners and aggregators for distribution system support services on a pay-for-performance basis. The bill sets the timeline for the Commission to make the program available as of January 1, 2025, and for IOUs to file tariffs for Commission approval by **July 1, 2025**.

Minnesota

Program Proposal Filing – In comments addressing its 2024-2040 Upper Midwest Resource Plan, Xcel Energy proposed a Distributed Capacity Procurement (DCP) process in Minnesota (functionally a VPP program) to integrate DERs into its planning. The program could procure anywhere from 400 MW to over 1 GW of DERs, depending on the needs of the system. With a theoretical target of 400 MW of energy storage and 440 MW of solar, the DCP could launch within 9-12 months and deploy within 36 months. Xcel Energy filed a joint settlement agreement in October 2024, during which it committed to file its DCP proposal by **October 2025**.

New York

Investigation – In April 2024, the New York State Public Service Commission initiated a "Grid of the Future" proceeding to transition the state to a more connected, affordable, resilient, and clean electric grid. The first part of this proceeding entails a Grid Flexibility Study, which will estimate the current and future potential capabilities of flexible resources across the state's grid. The study will also identify near-term actions to increase the deployment and use of flexible resources and improve their integration into planning and grid operations. The study will be completed by **January 31, 2025,** and will be used to create the New York Grid of the Future Plan, which will be completed by **February 28, 2025**.

North Carolina

Program Proposal Filing – In November 2024, as part of its decision in Duke Energy's Carolinas Resource Plan, the North Carolina Utilities Commission directed Duke Energy to work with stakeholders to develop a version of the utility's existing PowerPair solar-plus-storage incentive program for non-residential customers and to file an application with the Commission by **September 2025**.

Texas

Wholesale Market Participation – In early January 2024, the Electric Reliability Council of Texas (ERCOT) issued a revised governing document for Phase 2 of the Aggregate Distributed Energy Resource (ADER) program. The revisions amend some validation processes and allow ancillary service ADERs to participate in ERCOT's Contingency Reserve Service (ECRS). ERCOT filed a finalized Phase 2 governing document in late February 2024.

Phase 1 and 2 of the pilot limited the total registered MW capacity of all ADERs to 80 MW and 40 MW for each of Non-Spinning Reserve Service and ECRS. Under Phase 3, ERCOT proposes increasing these limits to 160 MW and 80 MW, respectively, to allow the pilot to continue to grow and evolve. ERCOT is also proposing to eliminate the load zone-based limits. The exact timing of Phase 3's launch is unknown but expected sometime in **2025**.

2024 VPP Actions by State

Arizona

Utility Managed Charging Program

In November 2023, Arizona Public Service (APS) filed its 2024 DSM Plan. The plan modifies APS's EV Charging Demand Management Pilot by offering an incentive of $500/charger for LMI customers, up to 100% of the charger's cost. (The standard incentive is $250/charger.) APS would also add two new incentives to the pilot. Behavioral Charging Rewards would offer an extra $5/month to customers who already participate in the Smart Charge EV data-share program if they limit their on-peak charging to once or less per month; a period of baseline charging would be required to receive the incentive, so new participants would only be eligible after participating for a few months in the data-share program. Active Managed Charging would offer $20/month to customers who allow APS to optimize their charging schedules during off-peak hours while ensuring that the car would be fully charged by a preset completion time.

In April 2024, APS filed an amended plan, removing incentives for residential connected Level 2 chargers, as the Arizona Corporation Commission's decision on its 2023 TEP concluded that these types of rebates cannot be funded by ratepayers. The budget will be shifted to the proposed Active Managed Charging program. [Docket No. E-01345A-23-0088]

Utility Storage or Multi-Technology Program

In March 2024, as part of APS's general rate case, the Arizona Corporation Commission issued a decision approving a BYOD storage pilot proposed by docket participants to run in conjunction with APS's Residential Battery Pilot. The pilot would use the same third-party aggregator as the existing program, with up to 5,000 customers. APS submitted its full BYOD Pilot proposal in August 2024. Participants would need to agree to participate in 60 DR events per year, lasting between one to four hours per event. The events would be scheduled between the hours of 4 p.m. and 10 p.m. during the summer season – from May 1 to October 31 each year – with a maximum of one event per day. Participating customers would be compensated with an annual $110/kW capacity payment based on the average kW performance delivered by their battery systems during all DR event hours called throughout the program season. [Docket No. E-01345A-22-0144]

Utility Storage or Multi-Technology Program

In November 2023, APS filed its 2024 DSM Plan. The plan would expand the ongoing Residential Battery Pilot to include two new tranches. (The original pilot is currently full, with 1,036 participating batteries.) Tranche 2 would include 250 customers with existing batteries, with participants receiving a $1,250 enrollment incentive. Tranche 3 would include 250 customers with new batteries, with participants receiving a $500/kW rebate, up to $3,750. Participants must agree to dispatch their batteries during on-peak periods and share up to 80% of their system's capacity for up to 100 events per year for three years. The proposed budget for the pilot is $1.61 million; money set aside for the Distributed Demand-Side Resource third-party aggregation tariff, which the Arizona Corporation Commission previously denied, would be allocated to the battery pilot expansion. APS filed an amended plan in April 2024 in response to Commission decisions in other dockets. The utility is removing the proposed Tranches 2 and 3 from the Residential Battery Pilot; instead, it will develop the BYOD Battery Pilot approved in its most recent rate case. [Docket No. E-01345A-23-0088]

California

State Storage or Multi-Technology Program

In July 2023, the California Energy Commission (CEC) approved a new incentive program to access customer-owned VPPs and other resources. The Demand Side Grid Support (DSGS) program will compensate eligible customers for upfront capacity commitments and per-unit reductions in net energy load during extreme events achieved through reduced usage, backup generation, or both. In March 2024, the CEC filed proposed modifications to the DSGS Guidelines. The modifications were intended to scale the program and ease participation. The CEC formally adopted the new guidelines in May 2024.

In October 2024, the CEC released further draft modifications to the DSGS program guidelines. The draft guidelines modify Option 3 (Market-Aware Behind the Meter Battery Storage Pilot) by increasing the minimum portfolio nominal power rating from 100 kW to 500 kW. It also applies a “residential” baseline to all batteries and clarifies that providers serving as VPP aggregators can enroll partner companies’ aggregations as separate VPPs. It also adds day-of Energy Emergency Alert (EEA) triggers for bonus compensation.

The new guidelines also add a new Incentive Option 4: Emergency Load Flex VPP for dispatchable smart thermostat-controlled HVAC or heat pump heating/cooling units, heat pump water heaters, and electric resistance water heaters. To be eligible to serve as a load flexibility VPP aggregator under Option 4, aggregators must aggregate a minimum of 500 devices across all utility service territories. Load flexibility capacity incentive payments will be made to load flexibility VPP aggregators based on the nominated and demonstrated capacity of each aggregation by month. [CEC Docket No. 22-RENEW-01]

State Storage or Multi-Technology Program

A proposed decision issued by the California Public Utilities Commission in February 2024 implements A.B. 209 of 2022, which allocated an additional $280 million to the Self-Generation Incentive Program (SGIP) for low-income solar-plus-storage systems. The incentive levels for solar are set at $3.10/Wh for both single-family and multifamily projects, and the storage incentive is set at $1.10/Wh. In March 2024, the Commission approved the $280 million budget for the SGIP Residential Solar and Storage Equity program and proposed incentive levels. The decision also required program administrators to ensure that incentive applicants are required to enroll in an approved qualified DR program, and provided a list of the qualified DR programs offered by each IOU.

States Rules (Proposed Legislation)

A.B. 3111 would have created new requirements for the information provided by DER owners or aggregators to the California Public Utilities Commission regarding the type, size, location, and other aspects of DERs. The Assembly passed the bill in May 2024, but the bill did not advance before the end of the legislative session. [A.B. 3111]

State Target (Proposed Legislation)

S.B. 1305 would have required each load-serving entity to procure an increasing percentage of its resource adequacy obligation from VPPs. The requirement begins at 2.5% by 2028 and increases to 15% by 2035. The bill failed to advance before the crossover deadline. [S.B. 1305]

Colorado

Procurement

In March 2024, the Colorado Public Utilities Commission opened a docket to address Xcel Energy's acquisition of DR resources through competitive procurement as a part of the utility's electric resource plan. The docket will also cover questions on VPP implementation and DERMS that were not addressed in Docket No. 23M-0466EG, including what provisions should be included in a model contract to acquire DR resources through third-party aggregators, and whether data provided through that process can determine appropriate provisions for other VPP programs. [Docket No. 24M-0136E]

State Rules

In September 2023, the Colorado Public Utilities Commission opened a proceeding to explore third-party implementation of VPP pilots in Xcel Energy's service area, along with natural gas DR pilots and neighborhood electrification pilots. The goal of the proceeding is to identify the core objectives and timelines for the projects, set the main parameters and milestones for the RFPs, and set operational and reporting milestones for the pilots. In January 2024, the recommended decision outlined rules for the RFPs. Regarding the VPP pilots, the recommendation would require an RFP for a DERMS, which can then be used to manage a VPP. A VPP should be able to facilitate DR, to enhance customer experience, to conform load with supply, to manage distribution system load, and to achieve operational savings and efficiency. A pilot should focus on disproportionately impacted communities and income-qualified customers.

The Commission issued a decision in April 2024 adopting the recommended decision, with modifications. The DERMS RFP will be split into two phases: Phase 1 covers the technical requirements outlined in the recommendation (aggregator DERMS), while Phase 2 covers the technical requirements outlined by Xcel in its exception to the recommendation (grid DERMS). The decision requires the RFP to be completed in time to support the Phase 1 pilot, which is to begin operations in September 2024. Phase 1 and Phase 2 should be operational by November 2025 and Q1 2026, respectively. [Docket No. 23M-0466EG]

State Rules

S.B. 218, enacted in May 2024, requires Xcel Energy to propose VPP programs, along with a tariff for performance-based compensation, due to the Colorado Public Utilities Commission by February 1, 2025. The program should allow prosumer and DER aggregator participation; Xcel Energy may participate as a DER aggregator. The compensation structure should be based on local and system peak demand reduction, clean peak service, voltage support and other ancillary services, avoided cost of T&D upgrades or capacity expansion, locational value, use of telemetry, and other functions the Commission chooses. The bill also requires Xcel Energy to identify interconnection and load hosting capacity for DERs in disproportionately impacted communities. [S.B. 218]

Utility Managed Charging Program

In December 2023, Xcel Energy filed its 2024-2026 DSM and Beneficial Electrification Plan. Xcel Energy included a proposal to make its Charging Perks Pilot a permanent program and remove the participant cap. Under the pilot, the utility controls customer's EV charging by matching it to real-time grid conditions, such as low electric costs or high amounts of renewables. The permanent program would offer a $50 enrollment incentive and a $50 participation incentive, depending on the customer's charging rate. The Public Utilities Commission approved the program provisions in September 2024. [Docket No. 23A-0589EG]

Utility Storage or Multi-Technology Program

In December 2023, Xcel Energy filed its 2024-2026 DSM and Beneficial Electrification Plan. In the plan, Xcel Energy proposed making the Residential Battery Demand Response Pilot a permanent program (i.e., the Renewable Battery Connect program). Storage systems must be 100% powered by on-site solar to be eligible, and participants will receive enrollment and participation incentives in return for discharging their battery to the grid upon request. DR events are limited to 60 per year, and an event cannot use more than 60% of a battery's capacity. The enrollment incentive is $500/kW, up to 50% of the cost; income-qualified and disproportionately impacted community customers can receive $800/kW, up to 75% of the cost. The participation incentive is $100/year. Xcel Energy filed a settlement agreement in May 2024, which does not make any major changes to the programs, adopting them as proposed. As part of the settlement, the utility agreed to consider a commercial battery pay-for-performance pilot. The Public Utilities Commission approved the settlement agreement in September 2024. [Docket No. 23A-0589EG]

Utility Storage or Multi-Technology Program

On December 16, 2024, as part of its 2025-2029 distribution system plan, Xcel Energy described a new VPP program it plans to implement called Prime Time VPP. The new program will incorporate new DERMS components called aggregator DERMS (ADERMS) and grid DERMS (GDERMS). The program will include participation both through utility programs and through third-party aggregators. The project involves cooperation with the City of Boulder, the University of Colorado Boulder, and the National Renewable Energy Laboratory. According to a City of Boulder news release, the program will involve participation by distributed solar-plus-storage, EV chargers, and smart thermostats. The program has been selected for award negotiations for funding from the U.S. Department of Energy under the Distributed Energy Systems funding opportunity. [Docket No. 24A-0547E]

Connecticut

State Managed Charging Program

In January 2024, the Connecticut Public Utilities Regulatory Authority (PURA) opened a proceeding for Year 4 of the EV Charging Program. In August 2024, utilities proposed to update their light-duty fleet-managed charging program. The utilities want to remove the customized managed charging pathway and integrated DR due to a lack of enrollment. The standard managed charging option and non-integrated DR would continue as-is. PURA filed a draft decision in November 2024. The light-duty fleet-managed charging program changes were partially approved; the integrated DR would end as requested, but utilities must continue the customized pathway. The residential managed charging program would continue with modifications. Baseline Tier (passive charging) would no longer offer summer DR events and their associated incentive; the non-incentivized/non-penalized emergency DR events would still continue for both Baseline and Advanced (active charging) Tiers. PURA issued a final decision in December 2024, adopting the draft decision with minor modifications. [Docket No. 24-08-06]

State Storage or Multi-Technology Program

In January 2024, PURA opened a docket regarding Year 4 of the Energy Storage Solutions Program. In November 2024, PURA issued a draft decision which modifies the commercial upfront incentives to have three declining blocks instead of four: first 50 MW, next 25 MW, and final 51.1 MW. Small projects would start at $182/kWh, Medium at $159.25/kWh, and Large at $91/kWh. Due to low residential participation, the order would also reallocate some future residential tranche capacity to the commercial side. Year 1 participants, who were allowed to participate in the forward capacity market, would be allowed to trade this right for a 25% adder on their upfront incentive as long as the system has not yet energized; market participation was available in Year 1, but was then replaced by the adder in Year 2. Storage aggregators would also now be eligible to submit applications. The program has had significant problems with customers meeting the base participation requirements (80% of energy dispatched across 90% of dispatch hours), with no program participants able to meet the requirements.

The draft decision would revise the formula used to calculate event performance and the formula used to calculate the upfront incentive clawback, so customers are proportionately penalized for underperformance instead of a flat fee. Underperforming participants would no longer be removed from the program after two fee violations; instead, additional clawback fees would be imposed. The program administrator could no longer waive clawback fees, and waivers must obtain PURA approval. The program administrator must submit a proposal by May 1, 2025, to change the upfront incentive model to a performance-based incentive model; the incentive would only be disbursed after reaching certain passive dispatch performance milestones. The passive dispatch window would be reduced from 3 p.m. - 8 p.m. to 5 p.m. - 8 p.m. The utilities would be authorized to hold ‘test’ dispatch events in March and April to prepare for the summer season. PURA filed a final decision in December 2024, adopting the draft decision with minor modifications. [Docket No. 24-08-05]

District of Columbia

Territory Storage or Multi-Technology Program

In November 2024, the D.C. Public Service Commission issued an RFP for a VPP or DERMS pilot project. The RFP seeks VPP or DERMS proposals that demonstrate the grid interactivity and interoperability of buildings and DERs. Respondents must include an enrollment process detailing customer participation and payment for services. Up to $5 million is available for the pilot, which must operate for at least two years. [Case No. GD-2020-02-M-95]

Georgia

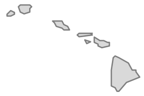
Utility Demand Response Program

In late October 2023, Georgia Power filed an update to its 2022 IRP, which includes new and amended DR incentive programs. One new proposed program – the curtailable load program (CL-1) – enables additional participation from C&I customers to reduce their load through long-term commitments during extreme supply and demand situations. This program differs from the utility's existing demand plus energy credit program by requiring longer-term contracts for more resource availability. Participants receive a credit commensurate with the capacity value associated with participation (i.e., load reduction is equal to the value provided to the grid). Georgia Power also proposed doubling the program cap from 25,000 to 50,000 for its existing residential thermostat program. Parties filed a stipulation in March 2024, which would approve the new CL-1 program and the utility's residential thermostat program amendments. In April 2024, the Georgia Public Service Commission issued an order approving the stipulation. [Docket No. 55378]

Utility Storage or Multi-Technology Program

In late October 2023, Georgia Power filed an update to its 2022 IRP, which includes new and amended demand response incentive programs. One new program is the DER colocation program (DCL-1), an optional C&I customer tariff allowing Georgia Power to own, operate, maintain, and control dispatchable DERs. Another new program is the DER customer-owned program (DCO-1), under which the utility will operate and control new customer-owned dispatchable DERs, and participating customers will receive a bill credit in exchange for utility dispatch use. Parties filed a stipulation in March 2024, which would approve the DCL-1 and DCO-1 programs. As part of the stipulation, Georgia Power will also evaluate and develop a residential and small commercial solar and battery pilot program as part of its 2025 IRP, and it will continue to investigate DER and grid-enhancing technological opportunities. In April 2024, the Commission issued an order approving the stipulation. [Docket No. 55378]

Hawaii



Utility Storage or Multi-Technology Program

In December 2023, the Hawaii Public Utilities Commission approved credit rates for the new Smart DER tariff and the incentive structure for Hawaiian Electric's (HECO) BYOD tariff, which would both take effect in March 2024. The December 2023 decision finalized the design of the BYOD tariff, which has three riders that provide varying levels of incentives based on the value of the grid services provided. Initially, the BYOD tariff will only be open to energy storage systems, but HECO will explore opening it to other devices in the future, including EV-to-grid systems. The initial capacity limits for the BYOD Tariff (inclusive of all three riders) are 70 MW for HECO, 17 MW for HELCO, and 19.9 MW for MECO. In March 2024, the Commission issued an order approving the final smart DER and BYOD tariffs with several modifications. These modifications include allowing customers to opt out of Advanced Rate Design TOU rates, removing or modifying language surrounding calculations for compensation, and replacing the term "solar" with "renewable" in the definition of BYOD-eligible devices. The Commission also delayed implementation of the tariffs until April 2024.

In December 2024, the Commission issued an order initiating Phase 4 of the proceeding to review and evaluate modifications to the BYOD program. The Commission conceded that the new BYOD is unpopular and does not add significant resources to the grid, further acknowledging that for the program to succeed, compensation provided for grid services must be clearly greater than the benefits of self-consumption. The Commission pointed to the Massachusetts ConnectedSolutions program as a possible model for a revised program, and requested comments from participants about it. Initial comments were due January 27, 2025, and a technical conference was held on January 30, 2025. [Docket No. 2019-0323]

State Rules (Proposed Legislation)

H.B. 1687 and S.B. 2986 would have required full retail rate crediting for exports from PV systems paired with battery storage as part of a utility-controlled grid service program. In addition to the retail credit for grid service exports, the Hawaii Public Utilities Commission would have been required to establish compensation values for resiliency, capacity, and ancillary services. The bill failed to advance before the session ended. [H.B. 1687 / S.B. 2986]

Idaho

Utility Demand Response Program

In October 2023, Idaho Power proposed to modify its Flex Peak Program (Schedule 82). Schedule 82 is the utility's C&I DR program used to reduce summer electricity demand. Idaho Power proposed to (1) modify the incentive payment structure, (2) add a performance waiver for customers participating in the automatic dispatch option when a load control device fails, (3) adjust the “day of” load adjustment definition, and (4) implement an advance notification option for customers that participate with 3 MW or more of nominated load reduction. These modifications are intended to improve participation and provide additional cost-effective capacity that can be dispatched to meet system needs. In April 2024, the Idaho Public Utilities Commission issued an order approving the modifications to the payment structures, the addition of a waiver provision covering participating customers whose load control device fails, and the revised definition of the “day of” load adjustment. The Commission also approved an advanced notification option for participants capable of large nominations as a five-year pilot, as proposed by Commission Staff. [Docket No. IPC-E-23-24]

Utility Demand Response Program

In September 2024, Idaho Power submitted a request to modify two of its DR programs, Schedule 23 - Irrigation Peak Rewards Program, and Schedule 82 - Flex Peak Program. The filing proposed modifications to both programs, together and separately. The proposed revision that would impact both programs is the variable payment on the fourth event. Idaho Power is seeking to revise the threshold for the variable incentive payment for both programs – from beginning on the fifth event to beginning on the fourth event – to align with the three minimum event requirement.

The proposed modifications for Schedule 23 include making language clarifications and adding an early interruption option where events would end by 9 p.m. and participants would receive 50% of the standard incentive. The proposed changes to Schedule 82 are: (1) implementing a $1,500 reimbursement for participants who install load control devices; (2) adjusting the calculations for baseline cap on event days; (3) allowing day-of load modifications when a participant initiates a partial/complete shutdown of their facility site during the day-of load hour; and (4) increasing flexibility in the nomination process. In December 2024, Commission Staff recommended approving the proposed tariffs as filed. [Docket No. IPC-E-24-37]

Illinois

Utility Managed Charging Program

In July 2024, Ameren Illinois filed an update to its Beneficial Electrification Plan. Ameren proposed a new residential managed charging program that would offer a $50 enrollment incentive and a $10/month participation incentive. The plan also includes an electric school bus VPP pilot. The pilot would demonstrate the capability of aggregating electric school buses into a VPP. [Docket No. 24-0494, Docket No. 24-0578]

Utility Storage or Multi-Technology Program

In December 2023, the Illinois Commerce Commission, in an order regarding Commonwealth Edison’s (ComEd’s) Multi-Year Integrated Grid Plan, directed ComEd to include a VPP program in its refiled plan**.** In March 2024, ComEd filed an amended version of its Multi-Year Integrated Grid Plan, which included a VPP program. The VPP program would be open to residential customers with DERs, including smart thermostats and energy storage. The program would provide incentives to aggregators of these DERs to provide load curtailment during both planned (i.e., 24-hour notice) and unplanned events. The incentive level for the planned dispatch of VPP resources would initially be $11.50/kW and is based on PJM clearing prices. The incentive level for VPP dispatch during unplanned events would be $53.11/kW.

A proposed order issued in October 2024 recommended holding workshops to further develop the proposed VPP program. The Commission's final order, issued in December 2024, contained the same conclusion as the proposed order, directing stakeholders to participate in workshops to develop a VPP program. Workshop stakeholders would focus on: (1) customer eligibility, (2) compensation frameworks, (3) penalties for non-performance, and (4) event durations and notice requirements. The Commission specified that workshops will begin on an expedited schedule to facilitate a tariff filing within 180 days of the order. [Docket No. 23-0055]

Utility Storage or Multi-Technology Program

In December 2023, the Illinois Commerce Commission, in an order regarding Ameren Illinois' Multi-Year Integrated Grid Plan, declined to establish a VPP program for Ameren until the utility had submitted a statute-compliant Grid Plan. In its refiled Grid Plan, Ameren proposed to initiate a workshop process no sooner than four months after approval of its refiled Grid Plan to develop a VPP program. The workshop process would convene interested parties to determine a value for compensation specific to the VPP program. If a consensus program is not developed within the 120-day engagement period, Ameren will submit a program to the Commission for approval within 60 days of the conclusion of the workshops. In its final order approving Ameren's refiled Grid Plan, the Commission approved the proposed process for developing the VPP program. [Docket No. 23-0082]

State Rules (Proposed Legislation)

H.B. 5855 and S.B. 3957 would have directed electric utilities to develop VPP tariffs that allow for compensation of ADERs. The bills would establish tariff requirements and call for utilities to develop peak remediation programs to compensate DERs for participation in peak events. The bills did not advance before the end of the legislative session. [H.B. 5855 / S.B. 3957]

States Rules (Proposed Legislation)

H.B. 5856 and S.B. 3959 would have directed electric utilities to develop VPP tariffs that allow for compensation of ADERs. The bills would establish tariff requirements and call for utilities to develop peak remediation programs to compensate DERs for participation in peak events. The bills did not advance before the end of the legislative session. [H.B. 5856 / S.B. 3959]

Indiana

State Rules

In April 2024, the Indiana Utility Regulatory Commission (IURC) opened a docket to investigate the public utility status of DER aggregators. The IURC's final order, issued in December 2024, did not rule on the public utility status of DER aggregators as a class, instead finding that the IURC would consider the question on a case-by-case basis. [Docket No. 46043]

Utility Managed Charging Program

In June 2024, Indiana Michigan Power filed a petition for approval of an electric transportation plan. The plan includes a public-use V2G pilot and a residential managed charging pilot. The residential managed charging pilot will allow customers to choose between planned charging (scheduled by the customer) and smart charging (managed by the utility), with an incentive provided for participating in smart charging (either charging in the designated time window or allowing managed charging; both options provide an $8/month credit). Customers that participate in the residential pilot may not operate DG or net meter. Meanwhile, the V2G pilot allows the utility to provide capacity/peak shaving ($200 monthly per charging port) and event credits ($12 per event per charging port) to participants and will provide credits ($3,292 monthly credit or $79,000 lump sum) for V2G capable chargers to school and public fleet customers. [Docket No. 46090]

Kansas

Utility Managed Charging Program

In September 2024, Evergy Kansas Metro and Evergy Kansas Central filed an application for approval of their Phase 2 TEP. The portfolio includes a new residential managed charging pilot, which is split into two sub-programs: an opt-out passive program and an opt-in active program. The active program will pay a $50 enrollment incentive and a $10/month participation incentive and will allow Evergy to control participants' chargers. Participants must charge at home at least once a month and may not override Evergy's schedule more than twice per month. [Docket No. 25-EKCE-169-TAR]

Kentucky

Wholesale Market Participation

In December 2023, Duke Energy Kentucky filed an application to implement a net metering successor tariff and close its old net metering rate to new customers. The tariff would also prohibit customers from entering into DER aggregator arrangements for participation in wholesale markets other than one offered by Duke Energy. The Kentucky Public Service Commission issued a final order in October 2024, adopting the prohibition for legacy net metering customers but not for new DER customers, noting that it is premature to do so before PJM's aggregation tariffs are finalized. In October 2024, solar stakeholders filed a petition for rehearing to overturn the market prohibition. However, the Commission denied the petition in November 2024. [Docket No. 2023-00413]

Louisiana

Utility Storage or Multi-Technology Program

In November 2024, the New Orleans City Council opened a new proceeding to evaluate options to increase the availability of DERs in light of the frequency and intensity of severe weather events, rapidly changing climate conditions, and increased demand on the grid. Parties submitted proposals for changes to existing policies or programs in December 2024. Entergy New Orleans filed comments opposing the use of Settlement Credits (resulting from a settlement involving System Energy Resources Inc. (SERI)) to support third-party DER programs. Furthermore, the utility suggested that if the City Council is interested in implementing a third-party DER program, as proposed by other parties in the proceeding, then the utility should have the opportunity to present its own DER program proposal, such as an expansion of its Energy Smart battery program (existing VPP program).

Together New Orleans and the Alliance for Affordable Energy submitted joint comments proposing a new upfront incentive program for residential and small commercial battery storage systems using $32 million in SERI Settlement Credits. The proposed program would require enrollment in Entergy New Orleans' Demand Response Battery Energy Storage System program (Energy Smart). [New Orleans City Council Docket No. UD-22-03]

Maine

State Storage or Multi-Technology Program

In November 2024, Efficiency Maine filed its draft Triennial Plan VI for fiscal years 2026-2028. The plan is meant to deliver 137 MW of summer peak load reductions by 2028, as well as 1,700 new small commercial and residential battery systems. As part of this new plan, Efficiency Maine will expand its existing DER initiative by offering new pathways for participation from all DER measures. This includes an incentive for small batteries used for emergency backup power. This will be recognized as the Renewable Reliability battery measure, under which aggregators (original equipment manufacturers, third-party owners, and third-party electric load aggregators) are allowed to work out their own payment arrangements with customers (residential and small commercial) and compensate them based on performance.

Through this measure, Efficiency Maine will pay an incentive directly to the aggregator to manage the aforementioned payment transaction/arrangement. Efficiency Maine will initially offer $200/kW per year, to be paid directly to the aggregator based on the capacity made available during targeted peak hours. For customers who have already installed a battery system or installed their system outside the Renewable Reliability measure, Efficiency Maine will offer the chance to enroll their projects through its DERMS platform to receive performance incentives. This measure will be known as the Open Access Battery Incentive and is a continuation of an offer from the previous Triennial Plan V that was made for residential and small commercial customers with a storage capacity of up to 20 kW. [Docket No. 2024-00310]

Maryland

State Rules

H.B. 1256 and S.B. 959, enacted in April 2024, are titled the Distributed Renewable Integration and Vehicle Electrification ("DRIVE") Act. The bills direct the Maryland Public Service Commission to develop a program for IOUs to establish pilot or temporary programs to compensate DER owners and aggregators for distribution system support services on a pay-for-performance basis. The laws set a timeline for the Commission to make the program available by January 1, 2025, and for IOUs to file tariffs for approval by July 1, 2025. Distribution system support services include ancillary services and DR events up to 30 times per year. The laws instruct IOUs to recover costs for participating in and administering programs and offering incentives to customers within the year those costs were incurred where feasible. IOUs may pursue and use a performance incentive mechanism to cover costs associated with using DERs or VPPs. The laws allow the Commission to approve or require IOUs to offer incentives for customers to acquire and install renewable on-site generation systems if customers enroll in the pilot programs and participate in distribution system support programs for at least five years. The Commission may allow an increased incentive for LMI households. [H.B. 1256 / S.B. 959]

State Rules

In July 2024, the Maryland Public Service Commission initiated a proceeding to implement the DRIVE Act. The opening order directs stakeholders to comment on incentives or amendments needed for distributed renewable integration into Maryland's regulations. In October 2024, the Commission issued an order which allows (but does not mandate) IOUs to offer incentives for distributed renewable assets. Any utility offering such a program must include low-income households as part of the program design. The Commission also took steps to develop licensing requirements for DER aggregators. In December 2024, Maryland's Joint Exelon Utilities (BGE, Delmarva, and Pepco) filed a request for clarification on the nature of incentives pertaining to VPP technologies and DER aggregation within the DRIVE program. [Case No. 9761]

State Rules

In October 2024, the Maryland Public Service Commission opened a rulemaking to consider V2G regulations proposed by Public Conference 44's Interconnection Work Group to implement the provisions of the DRIVE Act of 2024. The proposed rules require V2G systems to submit an interconnection request to the corresponding IOU; IOUs must treat V2G systems as energy storage devices for review purposes. IOUs may study the potential impacts of V2G system interconnections and ensure that safety certifications are met for the systems prior to allowing parallel operation. Comments on the proposed rules were due in November 2024; the Commission held a rulemaking session in December 2024. [Rulemaking No. 87]

Massachusetts

Investigation

In May 2024, the Massachusetts Clean Energy Center (MassCEC) released an RFP for a consultant to create a state-specific, statewide compensation mechanism for DERs that are providing service to the state's grid, with a focus on valuing the locational services to the distribution grid. MassCEC is seeking a valuation methodology for locational grid services based on characteristics such as technology, type of grid service provided, level of availability, and level of utility visibility and control. The consultant must also create an implementation roadmap that would maximize long-term DER adoption and participation. Applications were due in June 2024, with final recommendations and deliverables due in April 2025. [MassCEC RFP]

Utility Storage or Multi-Technology Program

In January 2024, after developing its electric sector modernization plan (ESMP) and receiving recommendations from the Grid Modernization Advisory Council (GMAC), Eversource filed its final plan for approval. The plan includes $25 million in investment for new programs and demonstrations to advance VPPs and DER usage. The Massachusetts Department of Public Utilities issued a final order in August 2024 approving the ESMP and increasing the budget for VPP and DER investments. [Docket No. 24-10]

Utility Storage or Multi-Technology Program

In January 2024, after developing its ESMP and receiving recommendations from the GMAC, National Grid filed its final plan for approval. The plan includes $31 million for customer investments and programs to advance VPPs and DER usage for grid services. The Massachusetts Department of Public Utilities issued a final order in August 2024 approving the ESMP and increasing the budget for VPP and DER investments. [Docket No. 24-11]

Michigan

Investigation

In December 2023, the Michigan Public Service Commission launched a Demand Response Aggregation Workgroup to discuss several issues related to DR and DER aggregation. The workgroup met throughout 2024, discussing issues related to DER aggregation barriers and program administration, dual DER participation in wholesale and retail markets, mechanisms for utility procurement of ADERs, and utility DERMS deployment.

State Rules (Proposed Legislation)

S.B. 773 would have required the Michigan Public Service Commission to develop requirements for programs that would allow behind-the-meter generation and energy storage owners to be compensated for services they provide to the distribution system, including through DER aggregators. Programs could be administered by third parties. The bill did not advance before the end of the legislative session. [S.B. 773]

State Rules, Wholesale Market Participation (Proposed Legislation)

H.B. 4839 would have required the Michigan Public Service Commission to establish guidelines for a program that allows aggregators and individuals with behind-the-meter generation or storage to provide distribution system benefits. Participants would be compensated for providing electric energy, DR, load shifting, generation shifting, locational value, voltage support, and other ancillary services. Participants could also participate in the wholesale electricity market. The Commission would have also been directed to ensure that the program guidelines align with RTO implementation of FERC Order 2222, and IOUs would file a program proposal in their next rate cases. The bill did not advance before the end of the legislative session. [H.B. 4839]

Minnesota

Procurement

In February 2024, Xcel Energy filed its 2024-2040 Upper Midwest Resource Plan for its territories in Minnesota, Wisconsin, Michigan, South Dakota, and North Dakota. As part of comments it filed in Minnesota in August 2024, Xcel Energy proposed a Distributed Capacity Procurement (DCP) process to integrate DERs into its resource plan. The program could procure anywhere from 400 MW to over 1 GW of DER capacity, depending on the needs of the system. With a theoretical target of 400 MW storage and 440 MW solar, the DCP could launch within 9-12 months and deploy within 36 months. (Xcel noted that this is not a formal proposal, adding that it will file a formal application in a separate proceeding in 2025.) Xcel Energy filed a joint settlement agreement in October 2024, in which it committed to file the DCP proposal by October 2025. [Docket No. 24-67]

Missouri

Utility Demand Response Program

Ameren Missouri filed the fourth iteration of its Missouri Energy Efficiency Investment Act (MEEIA) Plan in March 2023. The MEEIA 4 Plan includes the continuation and modification of two DR programs – one for residential customers and one for business customers. Ameren proposed an expansion of the residential program to include resources such as water heaters or EVs as eligible. The utility also would like to call DR events for the Midcontinent Independent System Operator (MISO), locational, or seasonal demand needs, and events called by custom device programming. Ameren expects to enroll 80,000 customers in the residential program by the end of 2026. For the business program, Ameren would like to register capacity as a Load Modifying Resource in MISO. In January 2024, Ameren filed an amended and supplemented application to approve its DSM portfolio. The application does not include any new DR programs beyond what Ameren previously filed. Several parties filed a stipulation in October 2024 to approve the plan with minor modifications. In November 2024, the Missouri Public Service Commission issued an order approving the stipulation. [Docket No. EO-2023-0136]

Utility Demand Response Program

Evergy Missouri Metro filed a demand-side programs application in April 2024. The application includes a home DR program involving direct load control, either using customer-owned equipment with incentives or utility-provided equipment. It also includes a business DR program and a DR education program. Evergy filed a non-unanimous settlement agreement in September 2024. The settlement agreement references the residential and business DR programs but does not include specific details, while adding that no advanced DR is included in the business category. The Missouri Public Service Commission directed Evergy to file tariffs consistent with the settlement, and in December 2024, it issued an order approving the settlement agreement and tariffs. [Docket No. EO-2023-0369]

Utility Demand Response Program

Evergy Missouri West filed a demand-side programs application in April 2024. The application includes a home DR program involving direct load control, either using customer-owned equipment with incentives or utility-provided equipment. It also includes a business DR program and a DR education program. Evergy filed a non-unanimous settlement agreement in September 2024. The settlement agreement references the residential and business DR programs but does not include specific details, while adding that no advanced DR is included in the business category. The Missouri Public Service Commission directed Evergy to file tariff sheets consistent with the settlement; in December 2024, it issued an order approving the settlement agreement and tariffs. [Docket No. EO-2023-0370]

Nevada

Utility Managed Charging Program

In May 2024, NV Energy filed a 2024 TEP, which proposes a portfolio of managed charging programs for both residential and non-residential customers. NV Energy anticipates approximately 40 managed charging events per year. Most events will be issued during summer months to coincide with peak demand, but events will also be tested in the fall and spring shoulder seasons to determine the effective capability to actively shift EV charging to absorb excess renewable energy. Each event will be a throttle down of the charging equipment to a percentage of less than 100. NV Energy will test various levels of throttle to determine the optimal range for each customer class. The plan also proposed the continuation of a vehicle telematics-managed charging pilot to better understand managed charging working directly through vehicle telematics.

In December 2024, the Public Utilities Commission of Nevada issued a draft order accepting the plan, but not all of the related programs. The draft order approved the fleet and residential managed charging programs with some minor modifications, including a reduction in the enrollment incentive for the residential program from $250 to $100. It also denied the multifamily and workplace-managed charging programs over concerns that the mismatch between the bill payer and the EV owner will render them ineffectual. In December 2024, the Commission issued an order aligned with the draft order. [Docket No. 24-05041]

New Hampshire

Utility Storage or Multi-Technology Program

In late April 2023, Liberty Utilities filed its multi-year rate plan application, which includes a BYOD program as part of Phase 2 of the utility’s current storage pilot, allowing customers that procure eligible battery energy storage systems and enroll in the TOU rates for storage devices. The program would include a one-time $500 enrollment charge and a monthly $50 administrative charge, with initial enrollment limited to 150 customers for the first three years after program approval, after which the utility will file a report to potentially increase the participant number. At the time of filing, the utility was not prepared to include an empirically backed BYOD tariff schedule for customer compensation that would establish a firm rate for customers' storage devices assisting the utility in peak shaving. In November 2024, parties filed a settlement agreement that did not specifically mention the BYOD program; however, as specified in the agreement, Liberty will continue to use the existing TOU model to establish rates for the battery storage program. [Docket No. DE 23-039]

New Jersey

Investigation, Wholesale Market Participation

In March 2024, the New Jersey Board of Public Utilities filed an RFI from electric distribution companies (EDCs) and other parties interested in wholesale market participation of DER aggregations under FERC Order 2222. The specific questions are addressed to EDCs and to general stakeholders. Some EDC–focused questions address how utilities are preparing for DER aggregation, including specific processes under development; concerns about grid reliability for DER aggregation that have not been addressed by PJM or the Board to date; processes EDCs use to account for/support new DER technologies; cybersecurity or telemetry concerns; and pilot program plans. General stakeholder questions include concerns about dispute resolution, technical support needs, pilot program information, and performance tracking and monitoring. A technical conference was held in January 2025. [Docket No. EO24020116]

Utility Demand Response Program

In December 2023, Atlantic City Electric (ACE) filed a petition to implement efficiency and peak demand reduction programs for Triennium II, FY 2025-2027. The petition outlines a direct load control DR program, operated by ACE, with a cost of $19.7 million and a flexible load management program with a cost of $1.1 million. The flexible load management program will be a BYOD smart thermostat program, with incentives provided for ongoing participation. The direct load control program will also take the form of a BYOD smart thermostat program, but ACE may explore the control of other devices, such as EV charging stations and smart electric water heaters. The flexible load management program will utilize smaller adjustments and shorter increments, while the direct load control program will use a more traditional cycling and temperature adjustment strategy.

In October 2024, parties filed a stipulation that included the direct load control program, with an $18 million budget, and the flexible load management program, with a $1 million budget. In October 2024, the New Jersey Board of Public Utilities issued an order approving the stipulation. [Docket No. QO23120871]

Utility Demand Response Program

In December 2023, Rockland Electric Company (RECO) filed a petition for energy efficiency and peak demand reduction programs for Triennium II, FY 2025-2027. The petition contains a BYOD program for smart thermostat setpoint control by RECO, which customers can override. The BYOD program would pay $85 for initial enrollment, with an annual incentive of $25 starting in the second year. In October 2024, RECO filed a joint stipulation with no changes to the BYOD program from the initial proposal. In October 2024, the New Jersey Board of Public Utilities issued an order approving the stipulation. [Docket No. QO23120875]

Utility Managed Charging Program

In December 2022, RECO filed a petition for permission to implement a five-year (2023-2027) managed EV charging program –Smart Charge New Jersey – with an operational budget of $3.8 million. The program would incentivize off-peak charging, using RECO's existing time-of-day off-peak classifications during the summer months for approved residential EV chargers. Participation would require customers to connect their EV charger to an always-on Wi-Fi network and share data from the charger with RECO. The incentives offered for each participating charger are: a one-time $25 enrollment incentive, a $25 incentive for referring a friend, and an up to $90 annual participation incentive ($10 plus $20 per summer month, where peak charging is avoided). [Docket No. EO22120743]

Utility Storage or Multi-Technology Program

In December 2023, Public Service Electric and Gas (PSE&G) New Jersey filed a petition for energy efficiency and peak demand reduction programs for Triennium II, FY 2025-2027. The petition contains a DR program budget of $25 million, which will support a VPP demonstration. The VPP demonstration will network behind-the-meter energy storage to provide grid services.

The petition contains an incentive of $8,000 to $16,000 for 8 kW energy storage systems. Battery costs over the incentive amount would be eligible for on-bill repayments to PSE&G. In October 2024, PSE&G filed a joint stipulation with a DR program budget of $26 million, part of which is a VPP demonstration pilot that will offer a $5,000 incentive to customers to install an 8 kW battery energy storage system. In October 2024, the New Jersey Board of Public Utilities approved the stipulation. [Docket No. QO23120874]

New Mexico

Utility Demand Response Program

In November 2024, Xcel Energy filed its 2025-2028 Energy Efficiency Plan. The Residential Thermostat Rewards and Business Thermostat Rewards programs would continue, with modifications. The enrollment incentives for both would increase from $75 to $100. Xcel Energy proposed a new Interruptible Credit Option tariff that will offer bill credits to business customers who allow the utility to interrupt their load during periods of high demand. Participating customers may decide how much of their load is available for interruption (at minimum 300 kW), how many hours per year their load can be interrupted (40, 80, or 160), and whether to receive advanced notice of interruption (one hour before interruption or no notice at all). The value of the credit would vary based on the first and third factors, ranging from $2.31 to $7.72 in the summer and from $1.62 to $5.76 in the winter, while the second factor would determine how many credits are received. Participation contracts are for three years rolling if a customer's interruptible load is under 50 MW, and five years rolling if 50 MW or more. If customers cease participation within the first year, they must forfeit all received credits; later cancellations are subject to a fine if not properly notified. [Docket No. 24-00269-UT]

Utility Managed Charging Program

In June 2023, the Public Service Company of New Mexico (PNM) filed its 2024-2026 TEP, which includes a residential managed charging pilot with incentives for passive management and active management. Under the active program, participants will receive a $75 enrollment incentive and, in the second year, a $75 participation incentive. The active program allows PNM to control the rate and time of residential charging; customers may dictate their desired state of charge at a given time, and they may opt out of PNM's controls up to 15% of the time. A recommended decision issued in February 2024 approved PNM's plan with modifications. The managed charging program would only include an active participation pathway; passive participation would be removed from the program. The New Mexico Public Regulation Commission issued a final order in February 2024 adopting the recommended decision with minor modifications. [Docket No. 23-00195-UT]

Utility Managed Charging Program

In April 2024, Xcel Energy filed its 2025-2027 TEP. The utility's managed charging program would introduce a new Charging Perks active program. The active program would allow Xcel Energy to remotely optimize a participant's charger to align charging with the participant's needs, off-peak periods, and renewable energy curtailment; participants would receive a $50 enrollment incentive and a $50 annual participation incentive. The Charging Perks program is currently available in Xcel Energy's Colorado service territory. A recommended decision issued in October 2024 approved the program, with modifications. The recommended decision adjusts the participation credit to $70. The New Mexico Public Regulation Commission issued a final order in December 2024, adopting the recommended decision. [Docket No. 24-00120-UT]

Wholesale Market Participation

In October 2024, Xcel Energy filed an application for a Southwest Power Pool Integrated Marketplace (SPP IM) Demand Response Option Tariff; Xcel filed a similar application in Texas in August 2024. Xcel Energy seeks to address an expected capacity shortfall in 2027 with near-term voluntary DR options via participation in the Southwest Power Pool (SPP). The new tariff and corresponding standard customer agreement would offer a new pilot interruptible program for large general transmission customers. Participants could bid their load into the SPP IM as a DR resource. If the bid is chosen, the participant must interrupt their load during the hours requested by SPP. [Docket No. 24-00259-UT]

New York

Investigation

In April 2024, the New York Public Service Commission opened the "Grid of the Future" proceeding to help achieve the state's renewable energy goals through flexible resources. The first part of this proceeding will be a grid flexibility study where the current and future potential capabilities of flexible resources across the state's grid will be estimated. The study will also identify near-term actions to increase the deployment and use of flexible resources and improve the integration of these resources into planning and grid operations. This study will be used to create the New York Grid of the Future Plan, which will be completed by the end of 2024. In October 2024, NYSERDA released a Grid of the Future RFP to produce a comprehensive, integrated, actionable, and maintainable plan for updating the state's electric system to effectively and timely support the new and changing grid needs driven by increasing electrification and the increasing scale, distribution, and capabilities of DERs. [Docket No. 24-E-0165]

North Carolina

Utility Managed Charging Program

Duke Energy Carolinas filed an application in August 2022 for approval of a V2G pilot program. The pilot would be available to residential customers who lease bi-directional-capable EVs from a participating OEM and install an eligible EV charger. Duke Energy anticipated launching the pilot in early 2023, with the Ford F150 Lightning being the only EV initially eligible for the pilot. Duke Energy would pay an incentive directly to Ford to reduce the customer's monthly EV lease payments, based on a rate of $6.50/kW of eligible battery discharge capability. Participants must agree to allow Duke to discharge the EV's battery to reduce utility system demand. At the end of each 12 months of the pilot, if a participant's actual annual availability of the discharge capability exceeds the assumed capability, Duke will provide the participant with a $25 gift card.

In April 2023, the North Carolina Utilities Commission approved the pilot program for a period of two years. However, in November 2023, Duke Energy filed a motion to suspend the launch of its V2G pilot by 12 months, from January 1, 2024, to January 1, 2025, which the Commission approved. In July 2024, Duke Energy requested that the Commission allow it to withdraw its application and discontinue the development of the V2G pilot. In its filing, Duke explained that it has not observed any material changes in market conditions, the adoption rate of Ford F-150 Lighting EVs, or the development of bi-directional V2G software, and it does not believe any of these conditions will change significantly by January 1, 2025. In December 2024, the Commission issued an order approving the request. [Docket No. E-7 Sub 1275]

Utility Storage or Multi-Technology Program

In June 2023, Duke Energy filed an application for a new solar-plus-storage program called PowerPair, pursuant to the North Carolina Utilities Commission's order approving the utility's revised net metering tariffs. The three-year pilot program would provide an incentive of $0.36/W-AC for solar and $240/kWh for battery storage systems. The program would target two groups of participants - Cohort A and Cohort B - to study the behavior of each group. Cohort A would be served under Duke's Residential Solar Choice tariff including TOU rates and would have complete control of the use of their energy storage device. Cohort B would be served under the bridge rate, a transitional net metering tariff that does not include TOU rates, and would grant full control of their energy storage device to Duke. The program would be capped at 30 MW for each of the utilities. The Public Staff recommended the Commission approve the pilot program, but with a larger incentive of $500/kWh for energy storage. In January 2024, the Commission approved the PowerPair proposal, but with the larger incentive level recommended by the Public Staff. [Docket No. E-2 Sub 1287, Docket No. E-7 Sub 1261]

Utility Storage or Multi-Technology Program

In November 2024, the North Carolina Utilities Commission issued an order on Duke Energy's Carolinas Resource Plan. The order directs Duke Energy to work with stakeholders to develop a version of the PowerPair solar-plus-storage incentive program for non-residential customers and to file a proposal by September 2025. [Docket No. E-100 Sub 190]

North Dakota

Utility Demand Response Program

In October 2023, Xcel Energy proposed modifications to its Residential Controlled Air Conditioning and Water Heater Rider and Commercial Controlled Air Conditioning Rider

("Saver's Switch") to allow for increased DR control. Specifically, the proposal seeks to increase the maximum amount of load that can be controlled during a demand event by circling participants' air conditioning load from 50% to 60%. In addition, in the case of a NERC Level 2 system emergency, Xcel Energy requested the right to cycle up to an 80% reduction. In May 2024, Xcel withdrew its application; the program outlined in the application will continue to cycle as defined in the current tariff. [Docket No. PU-23-337]

Ohio

Utility Demand Response Program

In January 2023, AEP Ohio filed an application for approval of its Electric Security Plan (ESP), including a variety of energy efficiency and DR programs. AEP Ohio filed a joint stipulation in September 2023, in which the utility agrees to implement a smart thermostat DR rebate program for residential customers, with an annual cap of $5 million for the four-year ESP term, offering customers an initial $75 incentive toward buying a smart thermostat or $50 for those that already have one; and then $25 for each program year that the customer participates in at least 75% of the DR events. In April 2024, the Public Utilities Commission of Ohio issued an order approving and modifying the stipulation. (The modifications do not affect the smart thermostat program.) [Docket No. 23-0023-EL-SSO]

Utility Demand Response Program

In April 2023, FirstEnergy subsidiaries Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company filed an application requesting approval for their fifth ESP (ESP V). The plan includes a residential load control DR program that does not require AMI and is voluntary for customers who agree to have their air conditioner (and possibly other equipment) controlled by a company-selected vendor. The load control program will provide customer incentives for equipment control. The Public Utilities Commission of Ohio issued an order modifying and approving the plan in May 2024. The order denied the residential DR program, but directed the utilities to develop a smart thermostat rebate program. [Docket No. 23-0301-EL-SSO]

Utility Demand Response Program

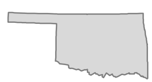
In April 2024, as part of its ESP, Duke Energy Ohio proposed a new residential DR program, Power Manager, that would involve direct load control of air conditioners during peak demand times. Participants would receive enrollment incentives and annual bill credits. Parties filed a stipulation in November 2024 that would adopt the ESP with unrelated modifications. Duke Energy also proposed the program as part of its 2024-2026 energy efficiency and DSM portfolio. [Docket No. 24-0278-EL-SSO (ESP), Docket No. 24-0046-EL-ATA (DSM Portfolio)]

Utility Managed Charging Program

In July 2022, the FirstEnergy utilities filed an application for approval of a second phase of their distribution grid modernization plan (Grid Mod II). Included in the proposal are three EV charging pilot programs: a residential EV charging program, a commercial EV charging program, and a commercial V2G charging program. Through the residential EV charging program, the utilities would monitor and manage up to 600 networked single-port EV charging stations at residential customer premises. Participants would receive an upfront incentive of $600, plus three annual retention payments of $50, each of which is contingent on continued participation.

The commercial EV charging program would be open to commercial customers (including governmental customers) who own or lease at least two EVs and charge the vehicles daily at a single location. The companies will monitor and manage up to 600 networked plugs, and each participant must have at least two plugs at a given site, resulting in a maximum of 300 total locations in the program. Participants would receive an upfront incentive of $1,250 plus three annual retention payments of $250 in each subsequent year.

Through the V2G program, the utilities anticipate enrolling six commercial or governmental customers, each with at least 10 EVs. The vehicles will be subject to managed charging similar to the commercial EV program and may also be dispatched by a DERMS to inject energy back into the distribution system for system support purposes. Participants will receive an upfront payment of $16,250 per EVSE and three annual retention payments of $1,250 in each subsequent year. In April 2024, parties filed a stipulation that withdraws the managed charging programs. In December 2024, the Public Utilities Commission of Ohio issued an order approving the stipulation. [Docket No. 22-0704-EL-UNC]

Oklahoma 

Utility Demand Response Program

In March 2024, the Public Service Company of Oklahoma (PSO) filed its 2025-2029 Demand Portfolio, which includes energy efficiency and DR programs. The residential portfolio includes changes to the Power Hour DR program, which would allow for year-round participation. The C&I portfolio includes changes to the Peak Performers DR program, also allowing for year-round participation. The program's budget allows for overall incentive levels of $58/verified kW-year. Both portfolios include research and development pilots.

PSO also proposed a Flexible Load Management pilot, which would include commercial auto-DR of building energy management systems, residential storage-plus-water heater controls (a continuation of a 2022-2024 pilot), and commercial standalone storage. For the standalone storage program, PSO will work with C&I customers with behind-the-meter battery storage and offer incentives to use the battery as a flexible load device. In September 2024, the Oklahoma Corporation Commission issued an order approving the portfolio with minor modification. [Docket No. PUD2024-000013]

Utility Demand Response Program

In July 2024, Oklahoma Gas & Electric (OG&E) filed its 2025-2029 Demand Portfolio, which includes energy efficiency and DR programs. OG&E is proposing a new Business Demand

Response program for medium and large C&I customers. Participants would curtail their load during specified events in return for inducements. Inducements would be based on the committed curtailable load and the customer's performance throughout the season. The program budget is $26.34 million across all five years. The Oklahoma Corporation Commission issued an order approving the full portfolio with minor changes in December 2024. [Docket No. PUD2024-000048]

Oregon

Utility Demand Response Program

In October 2024, Portland General Electric (PGE) submitted revisions to its Smart Grid Testbed (SGTB) pilot to add provisions for a new single-family demonstration. The Single Family New Construction Demonstration will provide: (1) upfront incentives to home builders to build flexible, load-enabled homes and (2) incentives to homeowners who enroll in DR programs. According to PGE, these incentives will encourage customers to enroll in the utility's current DR programs. Eligible homeowners located within a participating subdivision will automatically be eligible to receive a $10/month bill credit for allowing PGE to send and receive signals to their heat pump water heater. The Oregon Public Utility Commission approved the modifications in November 2024. [Docket No. ADV 1649]

Utility Demand Response Program

In October 2024, Idaho Power filed a request to modify two of its DR programs - Irrigation Peak Rewards (Schedule 23) and Flex Peak Program (Schedule 76). The proposed modifications to Schedule 23 include language clarifications and adding an early interruption option under which events last no later than 9 p.m.

The proposed modifications to Schedule 76 are: (1) adding reimbursement for participants who choose to automate their systems with load control devices; (2) updating how adjusted baseline caps are calculated on event days; (3) adding language to allow day-of-adjustment modifications for instances where a participant initiates a partial or complete shutdown of their facility site during the day of a load control event; and (4) adding flexibility to the nomination process. Idaho Power also proposed revising the threshold for the variable incentive payment for both programs, from beginning on the fifth event to beginning on the fourth event. The Oregon Public Utility Commission approved the filing in January 2025. [Docket No. ADV 1659]

Utility Managed Charging Program

In May 2024, PGE filed a request to revise its SGTB Pilot to add provisions for a new Vehicle-to-Everything (V2X) study. The V2X demonstration will assess the flexible load potential available to PGE via the ability to manage EV charging to shift customer demand, to leverage vehicle-to-home power to reduce demand during peak times, and to export power across the meter through V2G functionality during peak events. PGE will enroll 10-20 customers, who will receive a discounted installation through incentives provided to contractors. The Oregon Public Utility Commission approved the modifications in July 2024. [Docket No. ADV 1616]

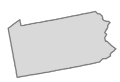
Utility Storage or Multi-Technology Program

In December 2024, Pacific Power proposed the creation of a new program under the provisions of its existing DR programs. The new program, Wattsmart Battery, has been operated by Pacific Power and other utilities owned by PacifiCorp in other states since 2020. The program, available to residential and commercial customers, would incentivize the installation of individual batteries. Customers will receive an enrollment payment of $150/kW multiplied by the commitment term (up to four years). This incentive is capped at 70% of battery equipment costs and will only be available for new battery purchases. Additionally, customers will receive an annual $15/kW incentive during the commitment term and an annual $50/kW if they continue to participate beyond the four-year commitment term. The utility may dispatch batteries to the system without advanced notice; however, the utility will not drain batteries below 10% capacity. [Docket No. ADV 1691]

Utility Target

In December 2024, PGE filed its 2024 distribution system plan, which includes a VPP strategy and benefit-cost analysis. The utility is targeting the development of flexible load programs, reaching 211 MW of summer capacity and 158 MW of winter capacity by 2028. It also set forth a goal of converting approximately 460 MW of distributed solar to at least 460 MW of distributed solar and storage providing grid services through the VPP platform by 2030. [Docket No. UM 2362]

Pennsylvania



State Rules

In February 2024, the Pennsylvania Public Utility Commission issued an Advanced Notice of Proposed Rulemaking (ANOPR) to solicit comments from stakeholders and interested parties on actions, additions, or amendments to Commission rules and regulations to support the implementation of FERC Order 2222. Order 2222 implementation has been largely through PJM's tariff filings with the FERC with processes to be executed by IOUs. The Commission is considering input on DER aggregations as a potential mechanism to increase efficiency, improve service, and lower costs. It seeks input on changes to DER interconnection rules, metering requirements, cost allocations for interconnections, distribution utility responsibility and DER management, small utility opt-in procedures, cybersecurity concerns, benefits of VPPs, billing issues, and equity concerns. [Docket No. L-2023-3044115]

Utility Storage or Multi-Technology Program

In May 2024, PPL Electric filed a petition for its second DER Management Plan. The plan includes making the current pilot for utility management of customer DER assets permanent and expanding the scope of the program to devices installed before the pilot began in January 2021 and other inverter-based DERs with no management devices presently installed. The petition also contains tariff updates with smart inverter settings and requirements, as well as specifications for DER management devices. [Docket No. P-2024-3049223]

Rhode Island

Utility Demand Response Program

In February 2024, Rhode Island Energy (RI Energy) filed its 2024-2026 System Reliability Procurement (SRP) Investment Proposal, which includes its ConnectedSolutions DR program. The ConnectedSolutions program would have a budget of $9.8 million in 2024, $10.5 million in 2025, and $11.6 million in 2026, with expected benefits of $11.7 million in 2024, $13.5 million in 2025, and $15.6 million in 2026. The existing residential and small business BYOT, C&I targeted dispatch, and C&I daily dispatch participation pathways will continue, with modified incentive levels. BYOT would increase its enrollment incentive from $25 to $50; the utility aims to enroll 4,000 new devices per year. Targeted Dispatch would decrease from $40/kW to $35/kW and Daily Dispatch would decrease from $300/kW to $275/kW; both would have an incentive cap of $1 million/customer/year. [Docket No. 24-06-EE]

Utility Managed Charging Program

In February 2024, RI Energy filed its 2024-2026 SRP Investment Proposal, which includes its ConnectedSolutions DR program. Rhode Island Energy is proposing a new residential and small business participation pathway for EV DR via active managed charging. Participants would receive a $50/vehicle enrollment incentive and a $20/season participation incentive. The utility would actively manage EV loads by remotely curtailing charging hours up to three times a year during the "peakiest" peaks. [Docket No. 24-06-EE]

Utility Storage or Multi-Technology Program

In February 2024, RI Energy filed its 2024-2026 SRP Investment Proposal, which includes its ConnectedSolutions DR program. The existing residential and small business battery participation pathway will continue, with modified incentive levels. Battery incentives would decrease from $400/kW to $225/kW; participants would keep the same rate for the first five years of participation, after which it would decrease to $200/kW. [Docket No. 24-06-EE]

South Carolina

Utility Demand Response Program

In June 2024, Dominion Energy filed an application for approval to continue its DSM programs for an additional five years. As part of the application, Dominion is proposing a new residential DR program. The proposed program consists of offerings designed to primarily address the utility's winter system peak. A Smart Thermostat Rewards offering will provide residential customers purchasing a smart thermostat with a $75 enrollment award and an annual $25 participation reward. In December 2024, the South Carolina Public Service Commission issued a directive approving the DSM programs, including the residential DR program. [Docket No. 2024-192-E]

Utility Demand Response Program, Utility Storage or Multi-Technology Program

In November 2024, Duke Energy filed an application to update its DSM programs and modify the program designs. Its existing Equipment Control Rider provides incentives for customers to allow Duke to remotely control their HVAC systems, smart thermostats, and battery storage systems. Duke Energy proposed increasing the existing incentives for technologies, and adding a new upfront incentive for new participants in the HVAC program. It also proposed adding a water heater control option and updating the months included within the different seasonal participation periods.

Duke Energy's existing EnergyWise for Business Program is a DR program in which a customer’s load reduction during peak events may be determined and controlled by the utility through eligible devices, including smart thermostats. The program also offers an option that allows the customer to choose how much load to reduce during a winter peak event. Duke Energy proposed increasing the incentives and adjusting the months included within the different seasonal participation periods. [Docket No. 2024-303-E]

State Rules (Proposed Legislation)

H.B. 5118 would have authorized utilities to propose programs and customer incentives to encourage load-shifting by its customers. Such programs could include DERs, such as energy storage. These programs may also include aggregation of resources, including renewable energy microgrids. The bill ultimately went to a conference committee in May 2024 but was not enacted. [H.B. 5118]

South Dakota

Utility Demand Response Program

In October 2023, Xcel Energy proposed modifying its Residential Controlled Air Conditioning and Water Heater Rider and Commercial Controlled Air Conditioning Rider ("Saver's Switch") by allowing for increased DR control. Specifically, the proposal seeks to increase the maximum amount of load that can be controlled during a demand event by cycling participants' air conditioning load from 50% to 60%. In addition, in the case of a NERC Level 2 system emergency, the utility requests the right to cycle up to an 80% reduction. In April 2024, the South Dakota Public Utilities Commission denied the proposed tariff revisions. [Docket No. EL23-032]

Texas

State Demand Response Rules

In August 2024, the Public Utility Commission of Texas issued proposed rules to implement S.B. 1699 of 2023, which ensures customers are entitled to participate in DR programs and entitled to receive notice from their retail electric provider regarding emergency energy alerts and planned outages. The law also requires ERCOT to establish goals to reduce the average total residential load. ERCOT's rules should allow for the adoption of a program that must: (1) provide DR participation to residential customers where reasonably available, (2) promote the use of AMI, (3) ensure that the programs are able to respond to emergency energy alerts, (4) provide opportunities for DR providers to contract with retail electric providers, (5) ensure the program does not negatively impact vulnerable populations, (6) facilitate the deployment of AMI, (7) establish a method to calculate whether energy reduction goals are achieved, (8) provide for demand reduction in summer and winter, and 9) allow utilities who offer a DR program to obtain funding through an energy efficiency incentive program.

Commission Staff filed a proposed order in December 2024, adopting the rules with minor modifications. Staff clarified that customers could not enroll in both a DR program and an emergency response program. The Commission filed an order in December 2024, adopting the draft decision in full. [Docket No. 56966]

Utility Managed Charging Program

In January 2023, El Paso Electric (EPE) filed an application for approval of its EV-Ready Pilot Programs and Tariffs. The application includes EPE's EV Smart Rewards Pilot Program, which would provide incentives to residential customers for enrolling and participating in the utility's managed charging program. EPE would offer a $125 enrollment incentive and a $50 annual participation incentive. Customers would have to schedule 80% of their charging during off-peak periods per month to receive the participation incentive. Additional rewards could be earned by participating in low-carbon or other DR events ($1/event, up to 5 events a month). The pilot would be limited to 880 customers, run for two years, and have a budget of $804,947. The Public Utility Commission of Texas issued a decision approving the EV Smart Rewards Pilot in October 2024. [Docket No. 54614]

Wholesale Market Participation

In January 2024, ERCOT filed a revised governing document for Phase 2 of the ADER program. The revisions amend some validation processes and allow ancillary service ADERs to participate in ERCOT's Contingency Reserve Service. ERCOT filed a finalized Phase 2 governing document in February 2024. ADER Task Force workshops were held throughout 2024. [Docket No. 53911]

Wholesale Market Participation

In August 2024, Xcel Energy filed a DR tariff for participation in the Southwest Power Pool (SPP). (Xcel Energy filed a similar application in New Mexico in October 2024.) Xcel Energy wants to counter an expected capacity shortfall in 2027 with near-term voluntary DR options via SPP participation. First, Xcel Energy seeks to amend its Interruptible Credit Option (ICO) tariff in order to: (1) remove the 200 MW cap on customer enrollment, (2) clarify that customers cannot dual-participate in ICO and other interruptible load programs, (3) clarify that participants bear the costs of metering upgrades, and (4) introduce a standard tariff customer agreement.

Second, Xcel Energy wants to amend its general service tariffs to add a new Off-Peak Alternate Rider and corresponding standard customer agreement. Rider participants would allow Xcel Energy to interrupt any of their power use during peak hours, in return for a discounted generation capacity charge. Third, it proposed a new SPP Integrated Marketplace Demand Response Option (SPP IM) Tariff and corresponding standard customer agreement that would offer a new pilot interruptible program for large general transmission customers. Participants could bid their load into the SPP IM as a DR resource. If the bid is chosen, the participant must interrupt its load during the hours requested by SPP. [Docket No. 56921]

Vermont

Utility Storage or Multi-Technology Program

In January 2024, Green Mountain Power (GMP) requested approval for a new Energy Storage Access Program (ESAP), which would allow low-income customers to enroll in the existing Energy Storage System program (VPP and resilience program) without any upfront costs or lease payments. GMP would provide and maintain ownership of the energy storage equipment and offer a 10-year lease term with a 60-month renewal option. The tariff includes a $450 early termination disconnection fee, but no upfront or ongoing costs for participants. The Vermont Public Utility Commission approved the ESAP tariff rider in June 2024. [Docket No. 24-0145-TF]

Utility Storage or Multi-Technology Program

In April 2024, GMP filed a petition to amend its existing Energy Storage System tariff (VPP and resilience program) with additional equipment eligibility information. The allowable equipment under the tariff now adds a Tesla meter collar backup switch and equivalent compatible equipment as described in the company's lease agreement with the customer. The Vermont Public Utility Commission issued an order approving the tariff in May 2024. [Docket No. 24-1071-TF]

Utility Storage or Multi-Technology Program

In May 2024, GMP filed a proposal to treat additional capital investments supporting its existing Energy Storage System tariff (VPP and resilience program) under the New Initiative Tariffed Offerings provision of its multi-year rate plan. Furthermore, the utility requested approval to spend up to $15 million above the current budget for the program in order to meet growing customer demand. The Vermont Public Utility Commission approved GMP’s request in September 2024, but limited the budget to $11.3 million in additional capital investment, which, combined with the existing $3.7 million program budget, totals $15 million. [Docket No. 24-1715-PET]

Virginia 

State Rules

H.B. 1062 and S.B. 271, enacted in April 2024, clarify that customer-generators may participate in DR, energy efficiency, or peak reduction from dispatch of on-site battery service, provided that the compensation received is in exchange for a distinct service that is not already compensated by net metering. [H.B. 1062 / S.B. 721]

Utility Demand Response Program

In December 2023, Dominion Energy Virginia filed an application for approval of its 2023 DSM Update. The filing contains a new Phase XII Residential Smart Thermostat DR program with a three-year, $18.3 million budget, which would adjust participant thermostats during peak times. Participants would receive an enrollment and annual incentive. In July 2024, the Virginia State Corporation Commission issued an order approving the DSM Portfolio update. [Docket No. PUR-2023-00021]

Utility Demand Response Program

In December 2024, Dominion Energy Virginia filed an application for approval of its 2024 DSM update. Included in the update is a proposal for a new Non-Residential Curtailment Program. The program would target medium and large C&I customers, encouraging them to manually curtail their energy usage during times of peak system demand. [Docket No. PUR-2024-00222]

Utility Storage or Multi-Technology Program

In December 2024, Dominion Energy Virginia filed an application for approval of its 2024 DSM update. Included in the update is a proposal for a new Non-Residential DG Program and a new Residential Battery Storage Pilot Program. The Non-Residential DG Program will be implemented by a contractor responsible for enabling remote operation and monitoring the customers' power generators. The contractor will be responsible for dispatching load during curtailment events under the direction of the utility. Participants will receive an incentive to operate their backup generation during curtailment events for a total of up to 120 hours per year.

The Residential Battery Storage Pilot will provide an upfront incentive of $1,000 plus an additional performance incentive to residential customers who discharge their home battery storage systems when called upon during peak electrical demand. The pilot will target residential customers with a battery storage system controlled by an approved original equipment manufacturer with an incentive for participation in demand response events during times of peak system demand. During a DR event, the battery will be remotely discharged without the customer's active participation. Program participants will receive $100 per average kW over all events. [Docket No. PUR-2024-00222]

Washington

State Target

H.B. 1589, enacted in March 2024, requires large combination gas and electric utilities to achieve annual demand response and demand flexibility equal to at least 10% of winter and summer peak electric demand by January 1, 2027. The legislation effectively only applied to Puget Sound Energy. The Washington Utilities and Transportation Commission may require a higher target if it is determined to be cost-effective. The Commission may also accept lower-level achievement if it determines that this requirement is neither technically nor commercially feasible during the applicable emissions reduction period. [H.B. 1589]

State Target

In May 2024, the Washington Utilities and Transportation Commission filed a pre-proposal statement of inquiry with the Office of the Code Reviser concerning H.B. 1589, which was enacted in March 2024. The pre-proposal involves the requirement for the Commission to adopt rules for a cost test for emissions reduction measures achieved by large combination utilities. Since the initial filing, the Commission has held several technical conferences and workshops, along with soliciting comments.

The Commission filed draft rules related to integrated system planning September 2024 that include the new demand response and flexibility target adopted by the legislation. The Commission filed a new version of the draft rules in January 2025 and is accepting comments until February 20, 2025. [Docket No. U-240281]

Utility Managed Charging Program

In December 2023, Avista Utilities proposed revisions to its electric transportation programs and activities. Under these proposed changes, the current residential charging program will be discontinued and replaced with a Smart Charging program utilizing vehicle telematics and/or AMI. Participants of the new residential program will receive a sign-up incentive of up to $500, and additional ongoing incentives that act to maximize off-peak charging may also be offered with up to an additional $500/customer. Low-income residential customers may receive an upfront incentive of up to $2,000. The changes became effective in January 2024. [Docket No. EU-230987]

Utility Storage or Multi-Technology Program

In September 2024, Puget Sound Energy proposed revisions to existing DER tariffs and two new DER tariff schedules. One of the new proposed tariffs is the DER Technology Demonstration tariff (Schedule 640), which aims to make limited-scale DER technology demonstration projects available. The other new proposed tariff is the DER Products and Services tariff (Schedule 683), which sets forth terms and conditions for DER products and services available under other DER tariffs (numbered between 601 and 699) offered by the utility (including the utility’s VPP program). The changes became effective in October 2024. [Docket No. 240715]

Wisconsin

Investigation

In July 2024, the Public Service Commission of Wisconsin opened a proceeding to conduct an investigation on its own motion to review the distributed aggregation of retail customer resources. In September 2024, the Commission initiated the investigation, seeking comments on several questions: (1) Should the Commission take any measures related to the aggregation of retail customers while this investigation is pending?; (2) What are the benefits and downsides of allowing aggregation of retail customers?; (3) How should aggregation of retail customers be structured?; (4) How would aggregated retail customers be compensated? (5) What steps should the Commission take to ensure that any new processes align with Wisconsin law and MISO rules, including Order 2222 compliance? Parties filed comments in response to these questions in October 2024. [Docket No. 5-EI-163]

Wholesale Market Participation

On May 31, 2024, the Wisconsin Court of Appeals issued a decision reversing a previous order that had dismissed a case brought by the Midwest Renewable Energy Association challenging a policy determination by the Wisconsin Public Service Commission that had prevented retail customers from engaging in aggregated DR activities in wholesale markets. The court found that the policy determination had been adopted without using proper rulemaking procedures. A judgment implementing the order in the lower court was issued in August 2024. [Case 2021CV000041]

Wyoming

Utility Demand Response Program

In July 2024, Rocky Mountain Power filed an application for approval of a Demand Response Pilot Program for calendar years 2025-2029. The new program would provide for a C&I DR pilot program, with customers able to participate through both manual and automated curtailment. The program would provide up to $125/kW to customers participating in either the real-time or advance notice options, and up to $190/kW for customers participating in both options. Participants would be compensated annually based on the verifiable load that is available for dispatch through the year. [Docket No. 17625]

Conclusion

VPPs offer an opportunity to improve grid flexibility, integrate DERs, and support the transition to a clean energy future. By drawing on the examples of other states, industry stakeholders can design stronger programs, improve customer engagement, and address barriers to VPP adoption.

If you found the information helpful or if you would like to learn more about the methodology and underlying data, please let us know; as of the time of publication, February 2025, we are considering more periodic updates to this report and additional data sets and information related to the topics herein, and we appreciate your feedback. To alert us to new or missing data or a possible correction, or to learn more about NCCETC's and SEPA's ongoing VPP research, please email Autumn Proudlove (afproudl@ncsu.edu) and Lakin Garth (lgarth@sepapower.org).

NCCETC also publishes additional policy tracking reports through its DSIRE Insight platform. Executive summaries of these reports may be found here. SEPA produces research and reports related to its focus areas, including VPPs and supporting DERs, which may be found here.