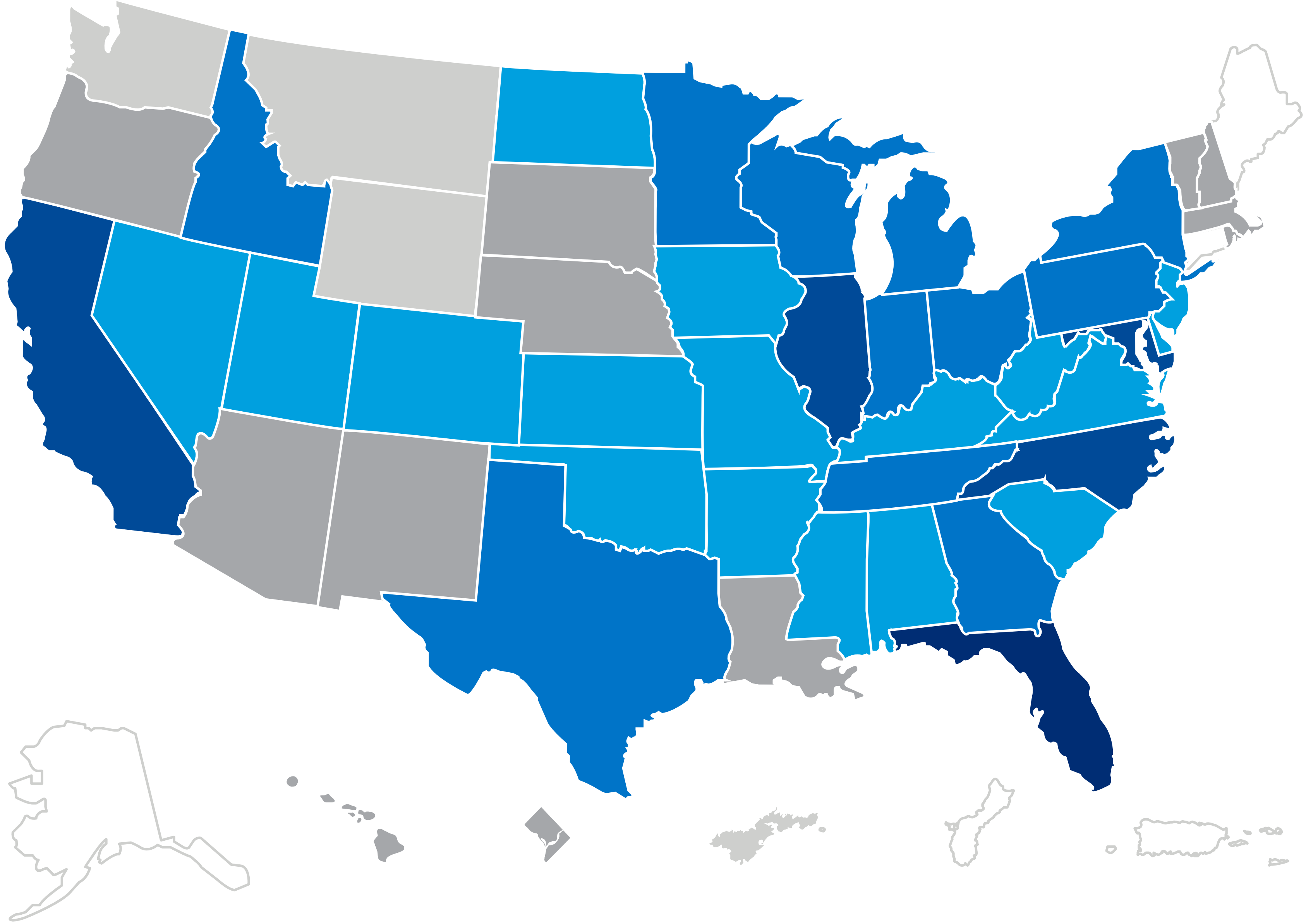
Smart Electric Power Alliance

2019 Utility Demand Response Market Snapshot

September 2019



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About SEPA

The Smart Electric Power Alliance (SEPA) is dedicated to helping electric power stakeholders address the most pressing issues they encounter as they pursue the transition to a clean and modern electric future and a carbon-free energy system by 2050. We are a trusted partner providing education, research, standards, and collaboration to help utilities, electric customers, and other industry players across four pathways: Transportation Electrification, Grid Integration, Regulatory Innovation and Utility Business Models. Through educational activities, working groups, peer-to-peer engagements and advisory services, SEPA convenes interested parties to facilitate information exchange and knowledge transfer to offer the highest value for our members and partner organizations. For more information, visit www.sepapower.org.

Disclaimer

As some information may be unintentionally missing, SEPA advises readers to perform necessary due diligence before making decisions using the report's content. Please contact SEPA at research@sepapower.org for additional information.

About the Report

The 2019 Utility Demand Response Market Snapshot is the result of SEPA's 2019 Utility Survey. Analysis of data collected from SEPA's 2019 Utility Survey seeks to provide deeper insight into utility demand response (DR) programs throughout the U.S., and represents 64% of total U.S. customer accounts (or 93 million customers). Data collected through this survey did not include third-party providers or aggregators, regional transmission organizations (RTOs), or independent system operators (ISOs). However, a more complete picture of the DR market, including efforts by third-party providers, and ISOs and RTOs, is provided in this report by Navigant Research. Please see the SEPA Survey Methodology for more information on scope and coverage.

SEPA began its annual survey of electric utilities in 2007, to track the capacity of new solar power interconnected to the grid each year. Now in its 12th year, the survey, since being expanded to cover additional topics, has collected three years of DR deployment data.

SEPA received additional content from Navigant Research, The Brattle Group, North Carolina Clean Energy Technology Center, and Parks Associates. Additional inputs included data and interviews with utilities as well as insights from industry stakeholders as noted in the acknowledgments.

Survey Methodology and Survey Coverage

SEPA conducted its annual Utility Survey between January and March 2019 using an online survey platform to collect data on utility DR programs through December 31, 2018.

SEPA encouraged participation through marketing efforts and direct outreach to key utility contacts. SEPA received DR data representing 190 utilities from across the U.S. Utilities with service territories in multiple states reported data from each state separately. Additionally, some utilities offer multiple programs under the same program type; these programs were counted as separate lines of data under the utility. Generation and transmission companies and federal utilities were counted as single lines of data and were not counted as responses for their distribution utilities. Please note that due to rounding, some totals may not correspond with the sum of the separate figures.

Demand Response Programs

Survey data was categorized into two customer segments and by respective DR programs: (1) **mass market** and (2) **commercial and industrial** (C&I) customers. Programs included in the survey were as follows:

Mass market includes DR programs offered to residential and small business customers.

- **AC switch**—A program allowing a grid operator to shed air conditioning load by using a control switch to remotely interrupt or cycle AC compressors.
- **Thermostat**—A program that uses smart thermostats to cycle air conditioners or home heating on and off or to adjust the temperature setting during the day.
- **Water heater**—A program that restricts customers' electric water heaters to run only at specific periods during the day. Water heater programs may also incorporate other DR strategies, such as storing hot water to shift load from on-peak to off-peak periods.
- **Behavioral**—Programs that incentivize customers to reduce use during peak periods with and without a supporting technology like those listed above. These programs may not have direct financial incentives for participation but can be tied to a time-varying rates program. Such programs include time-of-use, critical peak pricing, peak time rebates, and variable peak pricing. An example would be asking customers to reduce consumption through email, texts, social media, app notifications, or other communications during a system peak event.
- **Other**—Programs that are not covered by the above category definitions. Examples include ice storage, pool pumps, electric vehicle smart charging programs, or behind-the-meter generation combined with electric storage.

Commercial and industrial includes DR programs or agreements offered to medium and large commercial and industrial customers.

- **Automated**—A program under which a utility can remotely and automatically reduce a customer's load, or increase the output of behind-the-meter generation or storage, during a DR event.
- **Customer initiated with notification**—A program that allows a utility to send a signal or other notification informing its customers of a DR event and asking them to reduce their load or increase the output of behind-the-meter generation or storage by a specified amount over a period of time.
- **Other**—A DR program for large consumers that is not covered by the above categories (e.g., irrigation control).

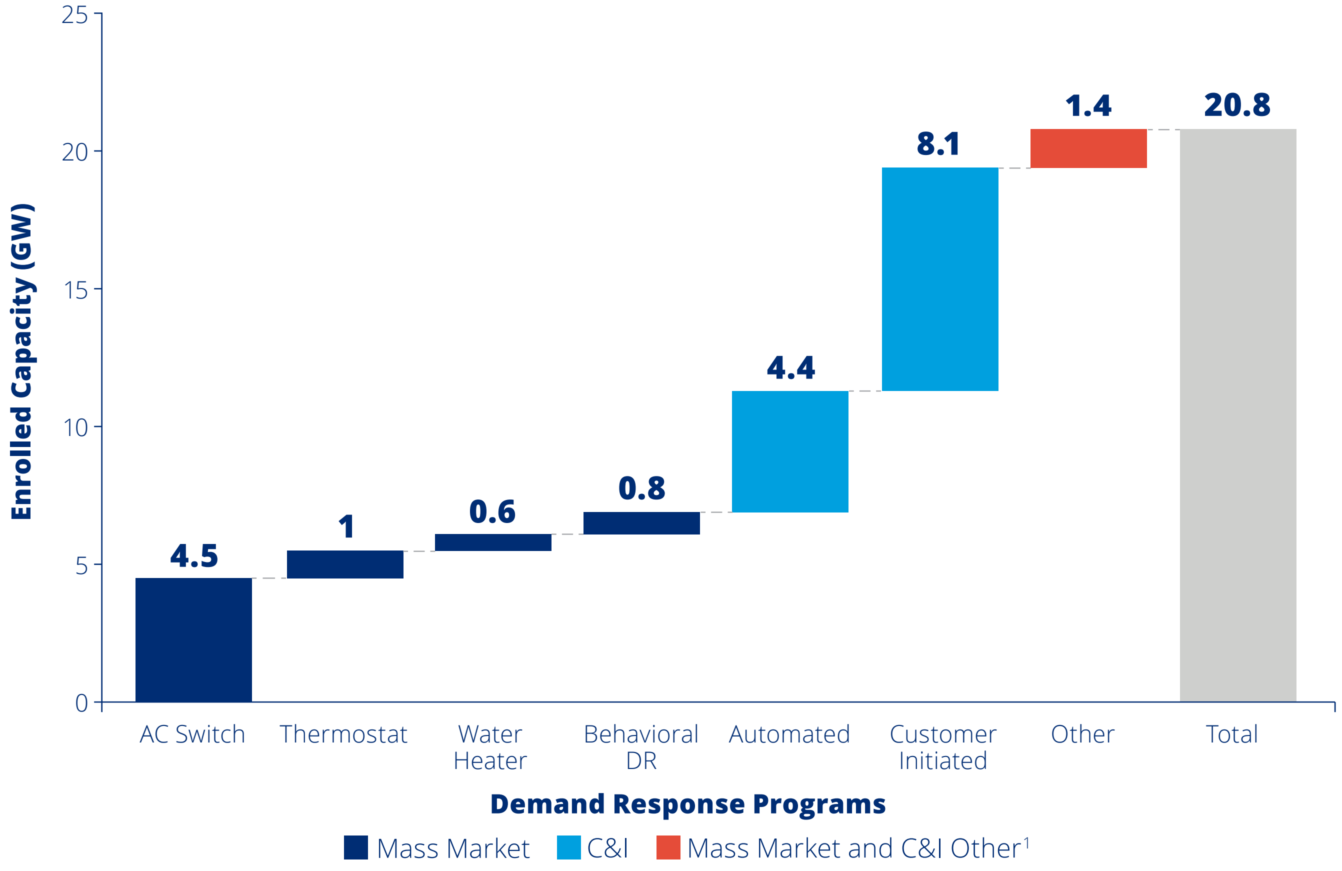
Results in each of these market segments are reported in terms of megawatts (MW) of enrolled and dispatched demand reduction capacity:

- **Enrolled capacity (MW)**—The total potential demand reduction available to the company for dispatch, based on customer enrollment in this DR program through the end of 2018.
- **Dispatched capacity (MW)**—The average actual demand reduction achieved during a dispatch of this DR program through the end of 2018.

Executive Summary

National Utility Demand Response Market Insights

Figure 1: 2018 Enrolled Demand Response Capacity (GW) by Program Type



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

MW = Megawatts-ac

- Utilities reported a demand response (DR) **enrolled capacity of 20.8 GW**, and a **dispatched capacity of 12.3 GW** (59.2% of total enrolled capacity) in 2018, across both customer segments and 190 utilities.
- **Mass market** DR accounted for 7.4 GW of enrolled capacity, and 4.3 GW of dispatched capacity.
  - **Air conditioning switches** and **water heaters** continue to be popular offerings, with 35.8% of utility respondents offering AC switch programs and 27.9% offering water heater programs. These programs provide energy services, such as deferring capacity and encouraging economic energy usage.
  - The survey indicated an increase in advanced customer programs. Some legacy programs (e.g., 1-way AC switch thermostat programs) are being retired or phased out to introduce better tools in customers' homes, accommodate for new and decentralized generating sources, and provide more flexibility for demand-side resources.
- The **commercial and industrial** (C&I) market segment contributed over half of the total reported enrolled DR capacity in 2018 (13.3 GW).
  - Utilities are beginning to offer a suite of C&I program and technology options, thus increasing their ability to call on events more frequently and match customers to programs that meet their unique needs.
  - Utilities are interested in using C&I DR programs to defer or replace generation capacity (with 31.8% citing this as their primary purpose for C&I programs).
  - Additionally, C&I DR programs are being leveraged as non-wires alternatives for utilities seeking to defer traditional transmission and distribution upgrades.

1 Includes mass market other programs (e.g., pool pumps) and C&I other programs (e.g., irrigation control).

Policy Update

- Multiple states are drafting proposals for clean peak standards. On January 1, 2019, **Massachusetts** began requiring the Department of Energy Resources (DOER) to regulate a minimum percentage of retail electricity sales with clean generation sources or peak seasonal load reductions.
- Regulatory mandates are motivating utilities to integrate programs that have typically been operated independently (i.e., energy efficiency and DR). A few states, specifically **New York**, **Hawaii**, and **California**, are leading the integration of distributed energy resources (DER), including DR.
- State efficiency legislation, such as the **Missouri Energy Efficiency Investment Act**, permits utilities to implement DR programs and earn an incentive for the demand reductions achieved similar to the rate of return they would get for electricity sales. Such legislation incentivizes demand savings and peak load shaving. Additionally, the **Clean Energy DC Omnibus Amendment Act** requires the DC Commission to establish a working group to guide the development of utility-administered energy efficiency and DR programs. Previously only the DC Sustainable Energy Utility (DCSEU) could offer such programs. This action acknowledges the importance of EE and DR in meeting clean energy and climate-related goals.

Demand Response Market Trends

- The Brattle Group estimates 200 GW of economically-feasible load potential in the U.S. by 2030. This potential equates to 20% of 2030 U.S. peak load levels. The benefits of this load flexibility could save the U.S. energy sector more than $15 billion per year by 2030.
- Regulatory and market trends, coupled with technological innovations and a diversity of resources, are creating an ecosystem where DR programs can begin integrating more technology types.
- The embrace of carbon reduction programs in integrated resource planning is driving increased DR adoption. **Xcel Energy** announced in 2018 that it would deliver 100% carbon-free electricity to customers by 2050. According to their Upper Midwest Energy Plan proposal, Xcel commits to reducing carbon emissions by more than 80% in their eight upper midwest customer states by 2030. Xcel filed the plan with the Minnesota Public Utilities Commission on July 1st, 2019.[2] DR programs help meet these carbon reduction goals.
- Utilities are incorporating programs that leverage multiple technology types (for example, thermostats and battery storage) to create a portfolio of integrated DR programs, as opposed to individual programs. These programs aim to provide larger savings, appeal to more customers, provide multiple grid services, to be called on more frequently due to their flexibility, than traditional DR programs. New software and increased penetration of DERs are enabling this approach.
- Energy storage, electric vehicle managed charging programs, smart home technology, and transactive energy represent new applications and techniques for DR. These developments, arriving in the form of utility pilot programs, can allow for a more integrated approach to DR and the provision of grid services.

2 Xcel Energy. (2018). Xcel Energy aims for zero-carbon electricity by 2050. Retrieved from https://www.xcelenergy.com/company/media_room/news_releases/xcel_energy_aims_for_zero-carbon_electricity_by_2050

MW = Megawatts-ac

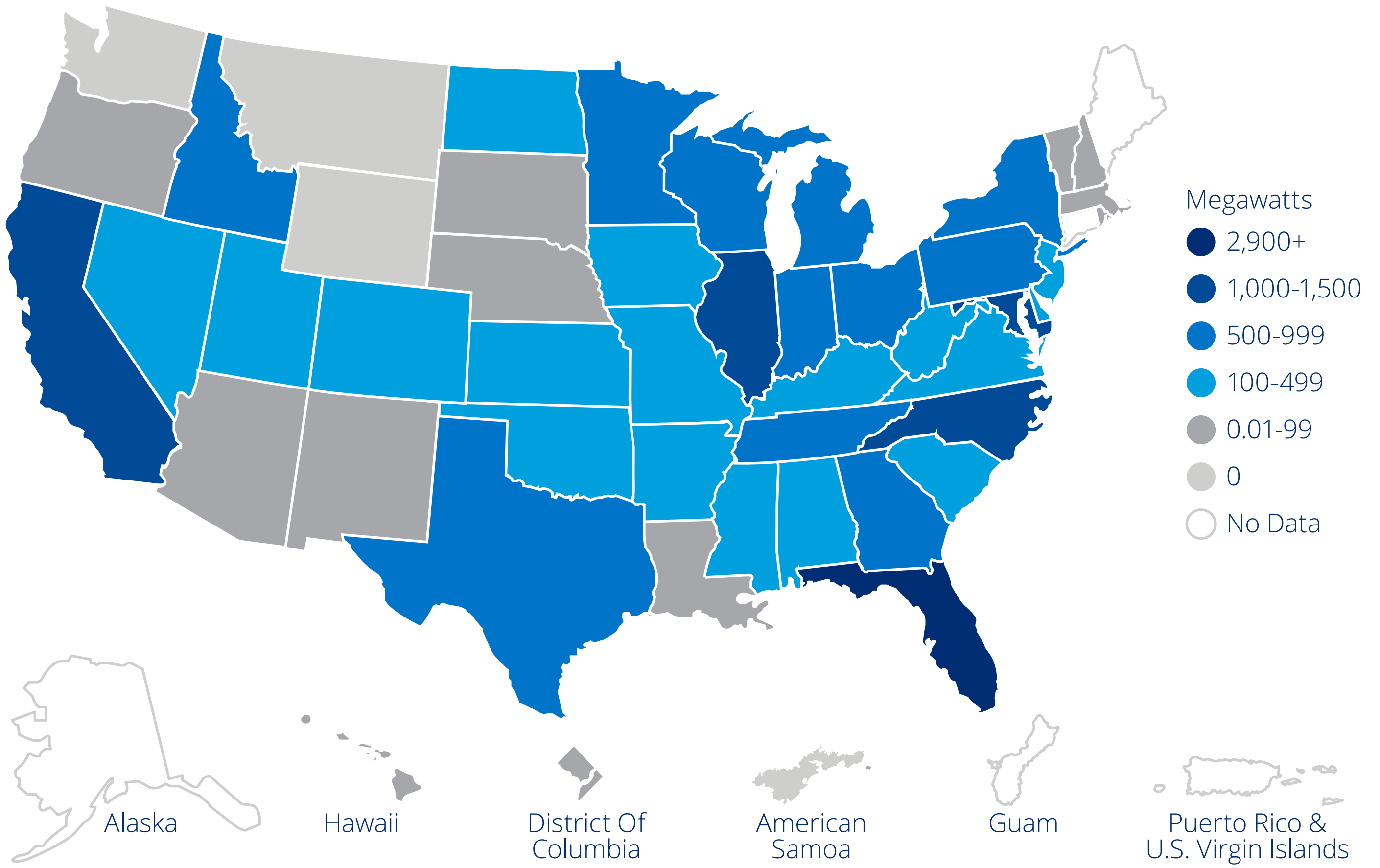
Introduction

SEPA's 2019 Utility Market Snapshot report builds upon its 2018 report with increased utility coverage (from 155 to 190 survey participants), updates on DR in the wholesale markets, and a fresh look at market trends.

Key Topic Areas:

- **Utility DR Market Summary:** This section includes results from the annual SEPA Utility Survey, and updates by utility DR program type (e.g., thermostat programs, water heaters) and customer segment.
- **Policy Updates:** This section, augmented by North Carolina Clean Energy Technology Center, provides updates on policies encouraging the growth of DR programs.
- **Wholesale DR Market Summary:** This section draws from Navigant Research and includes a market summary and analysis of DR changes in the wholesale markets.
- **DR Market Trends:** The final section of the report provides short summaries on DR market trends, including demand flexibility (contributed by The Brattle Group), energy storage, electric vehicle managed charging, smart home devices (contributed by Parks Associates), and transactive energy.

Figure 2: 2018 Enrolled Demand Response Capacity Map (MW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

MW = Megawatts-ac

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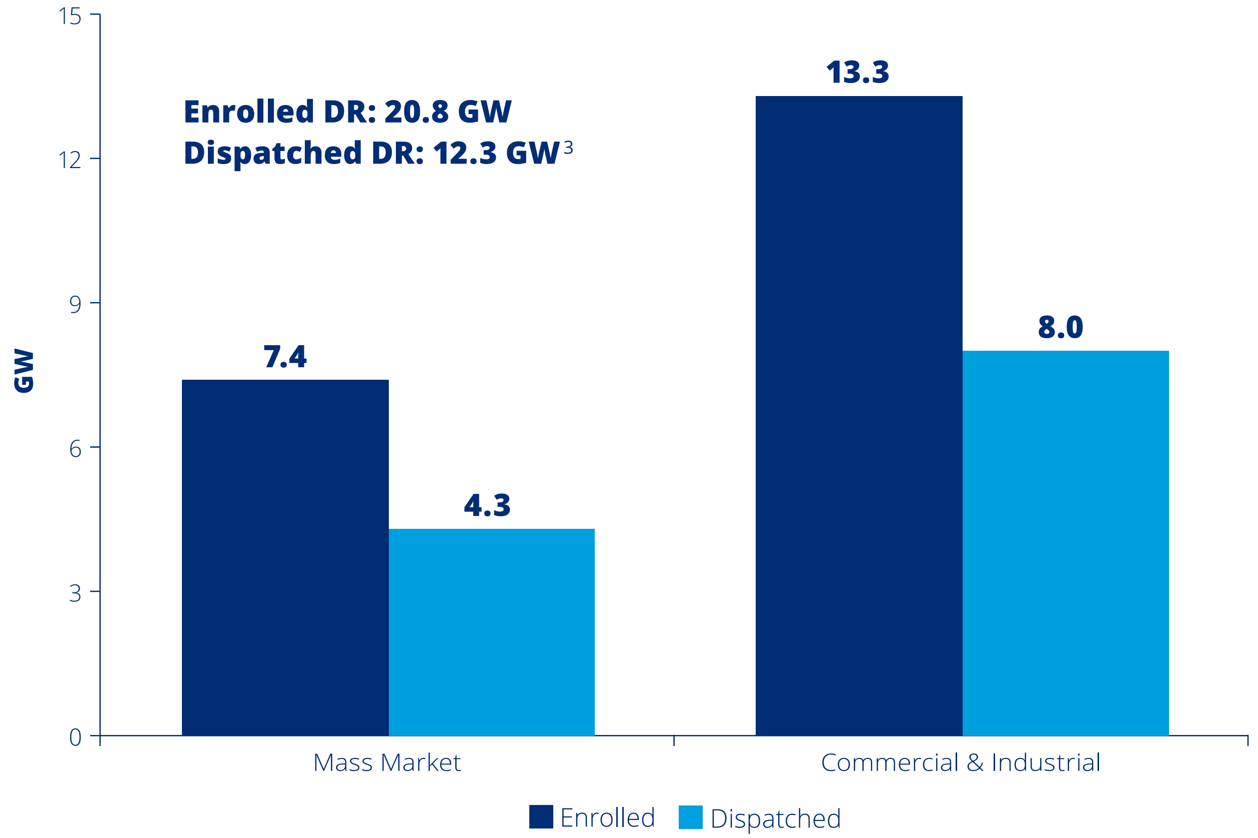
Utility Demand Response Market Summary

National Utility Demand Response Market Insights

Figure 3: 2018 Enrolled Demand Response Capacity (GW) by Market Segment



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

SEPA's 2019 Utility Survey captured dispatchable DR in both the mass market and commercial and industrial (C&I) segments representing approximately 64.7% of total U.S. customer accounts. Utility participants reported 20.8 GW of enrolled DR capacity in 2018.

Mass Market DR:

- Enrolled mass market DR was reported as 7.4 GW, 35.8% of total enrolled DR captured for 2018.
- At 4.5 GW, AC Switch programs provided the largest enrolled capacity of any mass market technology.

Commercial & Industrial DR:

- C&I DR accounted for 13.3 GW, or 64.2% of total enrolled DR.
- Customer initiated programs accounted for 8.1 GW or 38.9% of the total enrolled DR, making it the largest C&I contributor.

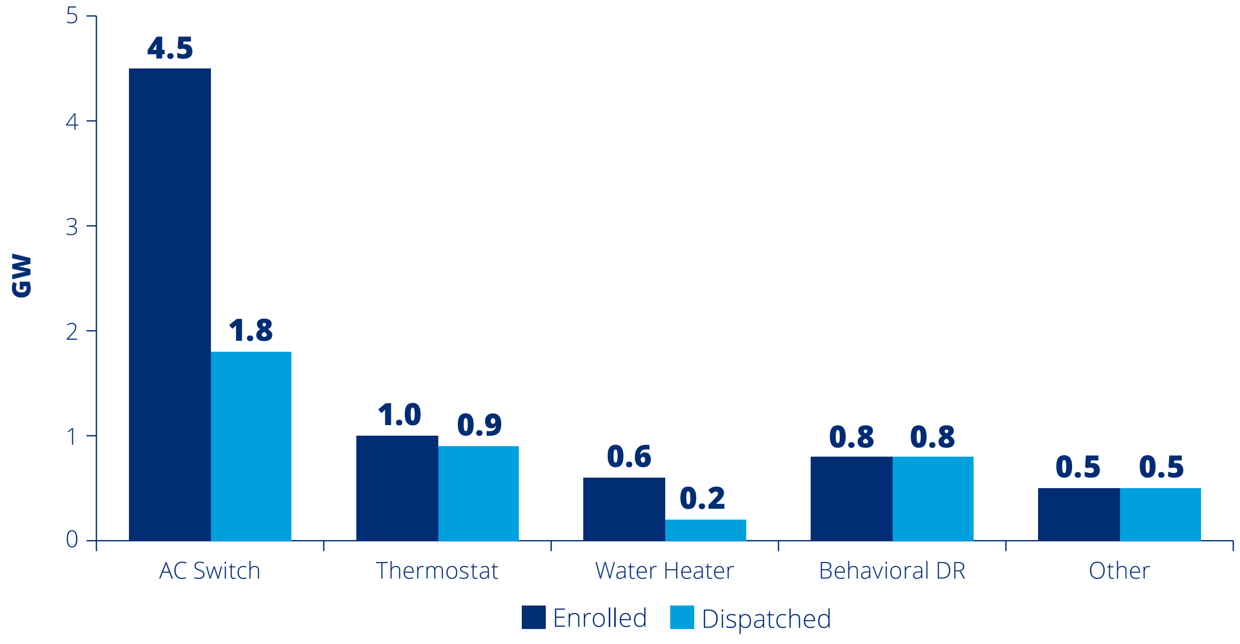
Through the survey and conversations with industry stakeholders, SEPA identified movement to more advanced DR programs. Expanded Bring Your Own Device (BYOD) programs, more integrated DR portfolios to leverage multiple technology types, and the adoption of smart home technology are all driving a transition from legacy programs and traditional DR to newer, more flexible programs and technologies.

3 Some utilities did not provide dispatched data, but reported calling numerous events during 2018.

MW = Megawatts-ac

Smart Electric Power Alliance

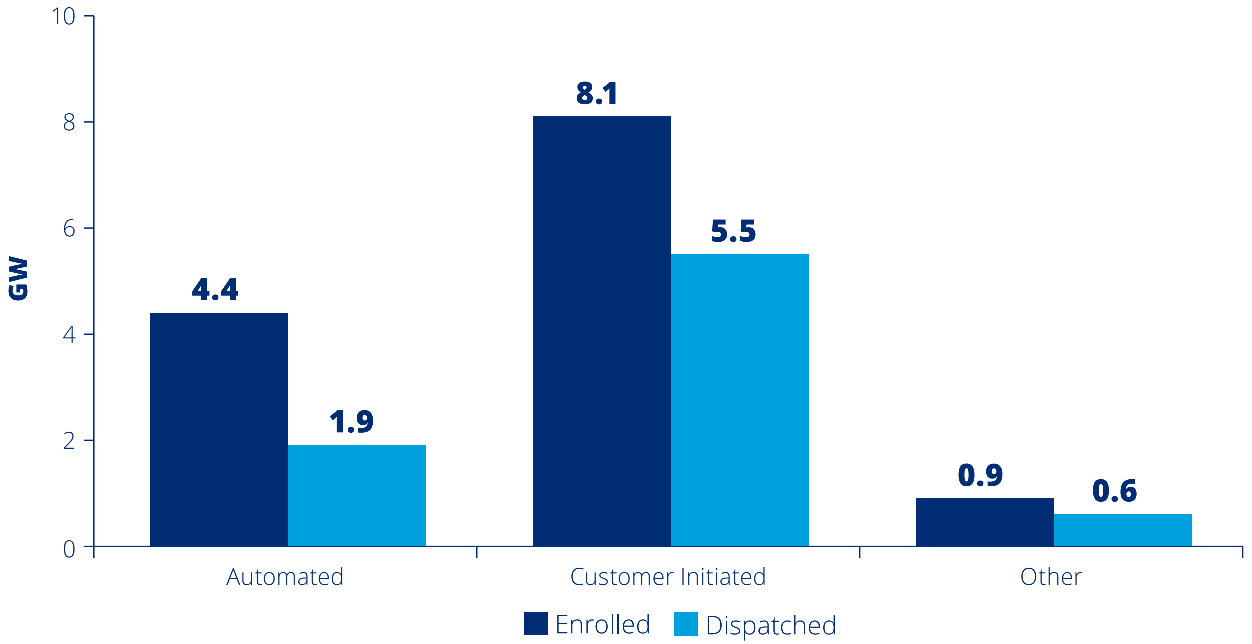
Figure 4: 2018 Mass Market Demand Response Capacity by Program Type (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

- AC switch programs continue to represent a majority (60.4%) of mass market enrolled capacity.
- A large majority of utilities using mass market programs (e.g., AC switch, thermostats, thermal storage) do so to defer or replace generation capacity. Additional motivators include: encouraging economical energy use and deferring transmission and distribution (T&D) capacity upgrades.

Figure 5: 2018 Commercial and Industrial Demand Response Capacity by Program Type (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

- Customer initiated programs represent a majority of enrolled capacity for C&I customers, at 8.1 MW (60.6%).
- Utilities using C&I programs primarily do so to defer or replace generation capacity and encourage economical energy use.
- Only 32 of the 190 utilities that participated in this year's survey had no DR programs (16.8% of survey participants). Of the 158 utilities with a DR program, 130 had a mass market program, 106 had a C&I program, and 76 utilities had both C&I and mass market programs.

MW = Megawatts-ac

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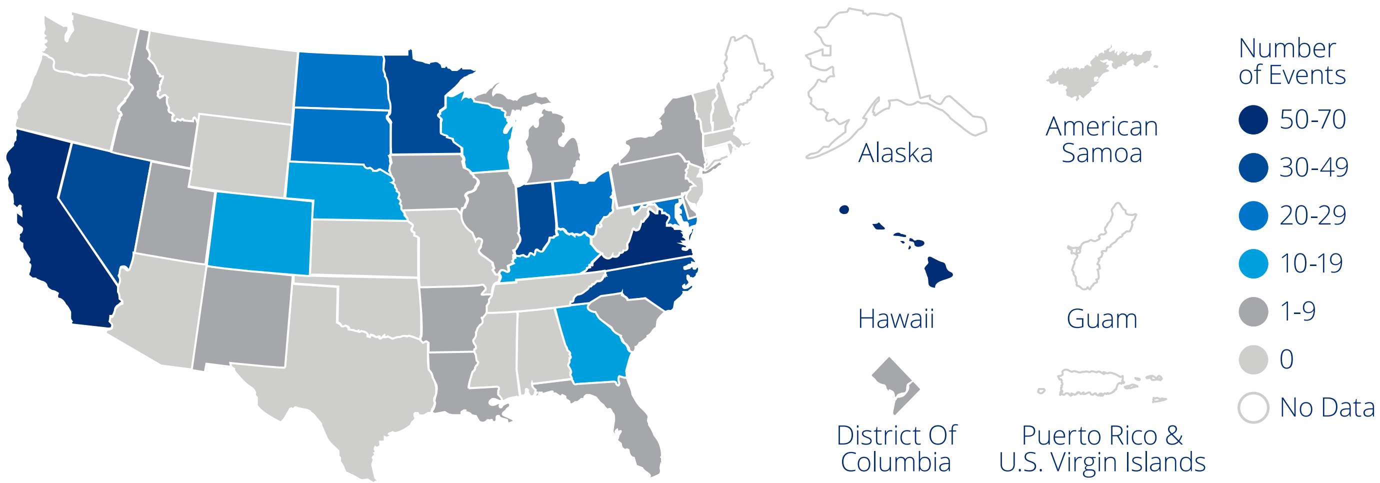
AC Switch Programs

Figure 6: 2018 AC Switch Program Summary

Enrolled Capacity: **4,491.2 MW**	Dispatched Capacity: **1,828.2 MW**

68 Utilities with Programs	**62** Utilities that Called an Event	**3.7** Hours Average Event Duration	**4.1** Million Customers Enrolled

AC Switch Events Called in 2018



Average Number of Events Called: **9.7**

Source: Smart Electric Power Alliance, 2019

AC switch programs are an established form of DR used by utilities over the past few decades. Many of these legacy programs rely on one-way communications (e.g., one-way radio paging).

Key Observations:

- Almost 21.6% of total DR enrolled capacity came from mass market AC switches.
- Programs use multiple AC switch technologies and delivery models, with 82.9% of programs using switches with one-way paging, 26.8% using two-way, and 9.8% offering both.
- 34% of respondents indicated that these programs are primarily used to reduce demand during load peaks.
- AC switch programs also serve to defer or replace transmission capacity (30.2%), provide operating reserves (17%), and encourage economic use (13.2%).

MW = Megawatts-ac

Moving Beyond the AC Switch

While the AC switch has been a key component of utilities' DR suites, this year's data showed a decrease in the number of enrolled customer devices (down about 10.7%) from utilities that participated in both 2017 and 2018 surveys.

A number of utilities reported significantly decreasing their AC Switch programs in 2018. Three utilities reported ending their program in 2018, and others reported reducing their programs by over half of their capacity.

Utilities cited multiple reasons for this move away from AC switches:

- AC switches are not cost-effective
- There is a lack of visibility into the devices
- Accounts were not performing due to removals, tampers, or inoperable devices and were no longer being included in utilities' DR numbers
- Customer participation was decreasing
- Customers were no longer being enrolled in the program
- The programs were no longer being marketed to customers
- The technology is old and there was no support for continuing the program
- Regulators did not support continued investment in AC switches

Additional reasons for retiring programs were gathered from industry interviews:

- Increasing customer choice through new programs
- Responding to customer satisfaction
- Lowering ongoing program costs

Differences Across Utility Types

Industry interviews indicated utilities are moving away from AC switch programs at different rates. Investor-owned utilities, which have significant investments in large AC switch programs, might be slower to move away from them. Whereas municipal utilities and cooperative utilities are able to adopt more device-based DR programs at a faster rate.

MW = Megawatts-ac

Electric Water Heater Programs

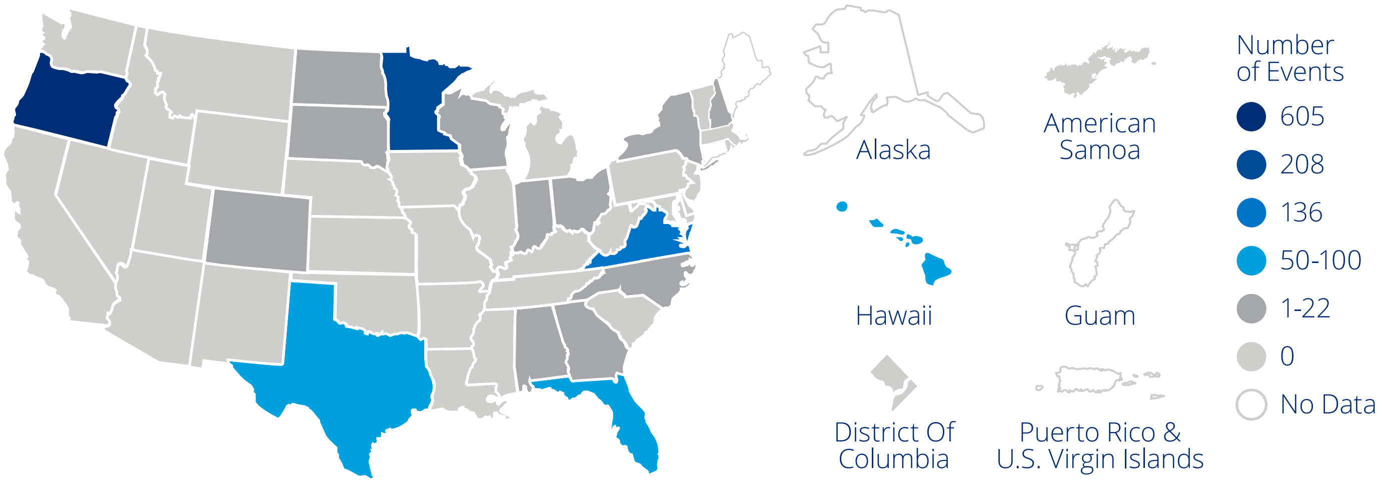
Figure 7: 2018 Water Heater Program Summary

Enrolled Capacity: **585.6 MW**

Dispatched Capacity: **202.7 MW**

53 Utilities with Programs	**27** Utilities that Called an Event	**6.0** Hours Average Event Duration	**1.3** Million Customers Enrolled

Water Heater Events Called in 2018



Average Number of Events Called: **42**

Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

Electric water heaters with switches constitute a widespread and low-cost storage opportunity. Across 53 utilities, electric water heater DR programs have a total enrolled capacity of 585.6 MW, representing 2% of the total enrolled DR capacity.

Because utilities consider water heater programs as non-disruptive to customers, they are called upon more frequently than other devices, indicated by the high average number of events. Additionally, water heater programs in areas like the Northwest can address winter peaking.

Key Observations:

- 11 states currently have grid interactive water heaters (GIWH) pilot programs: Arizona, California, Florida, Georgia, Hawaii, Minnesota, North Carolina, Oregon, South Dakota, Washington, and Wisconsin.[4] See pilot program highlights on page 15.
- Of the utilities that listed a primary program purpose for calling on water heaters, 51.7% said they utilized the program to defer or replace generation and transmission or distribution capacity.

4 Results from SEPA Utility Survey and interviews with industry experts.

Water Heater Program Highlights

In 2018, **Bonneville Power Administration**, **Portland General Electric**, and the **Northwest Energy Efficiency Alliance** completed the largest smart water heater pilot program to date; a three-year study that included 277 participants across eight utilities in the Northwest. The study found that heat pump water heaters can successfully participate in DR events, and be called on hundreds of times a year to reduce renewable curtailment and support increased penetration of renewables through load shifting. The study concluded that if 26% of Oregon's and Washington's electric water heaters participate in DR programs, the region could create 300 MW of storage capacity.[5]

In 2019, **EnergyHub** and **Rheem** partnered with **United Illuminating (UI)** in Connecticut to introduce an intelligent heat pump water heater pilot program. The pilot, which is part of UI's low-income program, plans to offer customers no-cost replacements of older electric water heaters with Rheem intelligent heat pump water heaters, which are integrated with EnergyHub's Mercury distributed energy resource management system (DERMS). The integration of Rheem water heaters and EnergyHub's platform can allow UI to predict, schedule, and dispatch DR calls to the fleet of GIWHs in order to shift energy usage during peak demand events.[6]

In 2019, **Pacific Gas and Electric (PG&E)** introduced the WatterSaver program, a behind-the-meter thermal energy storage program utilizing both heat-pump and electric-resistance water heaters to provide peak load reduction. PG&E set a goal of providing up to 5 MW of peak load reduction capacity by 2025. Initial estimates predict 2,500 to 6,600 units will participate in the program, which is currently still in the approval process.[7]

Shifted Energy is partnering with **Open Access Technology International (OATI)** to deliver 2.5 MW of GIWH to **Hawaiian Electric (HECO)** through Hawaii's recently launched Grid Services Purchase Agreement (GSPA) contract.

Following a 20-minute installation, Shifted Energy's off-tank controller and virtual power plant software converts traditional electric water heaters into distributed energy resources capable of providing valuable grid services such as DR, load building, and fast frequency response. Shifted's GIWH technology utilizes cellular communications and machine learning to accurately monitor and forecast a customer's hot water usage, enabling utilities to maximize each tank's grid service capacity while minimizing impact to the host customer's hot water availability. In return for allowing their water heaters to support Hawaii's grid, residents that participate in the GSPA will receive a monthly bill credit between $3 and $5 over the next 5 years.

Previous GIWH pilots between Shifted and HECO demonstrated that: (1) water heaters are one of the few ways that a multi-family building dweller or renter can participate in utility programs; (2) customers are excited to support state clean energy goals when offered a participation pathway; and (3) intelligently controlled water heaters can successfully provide multiple grid services.

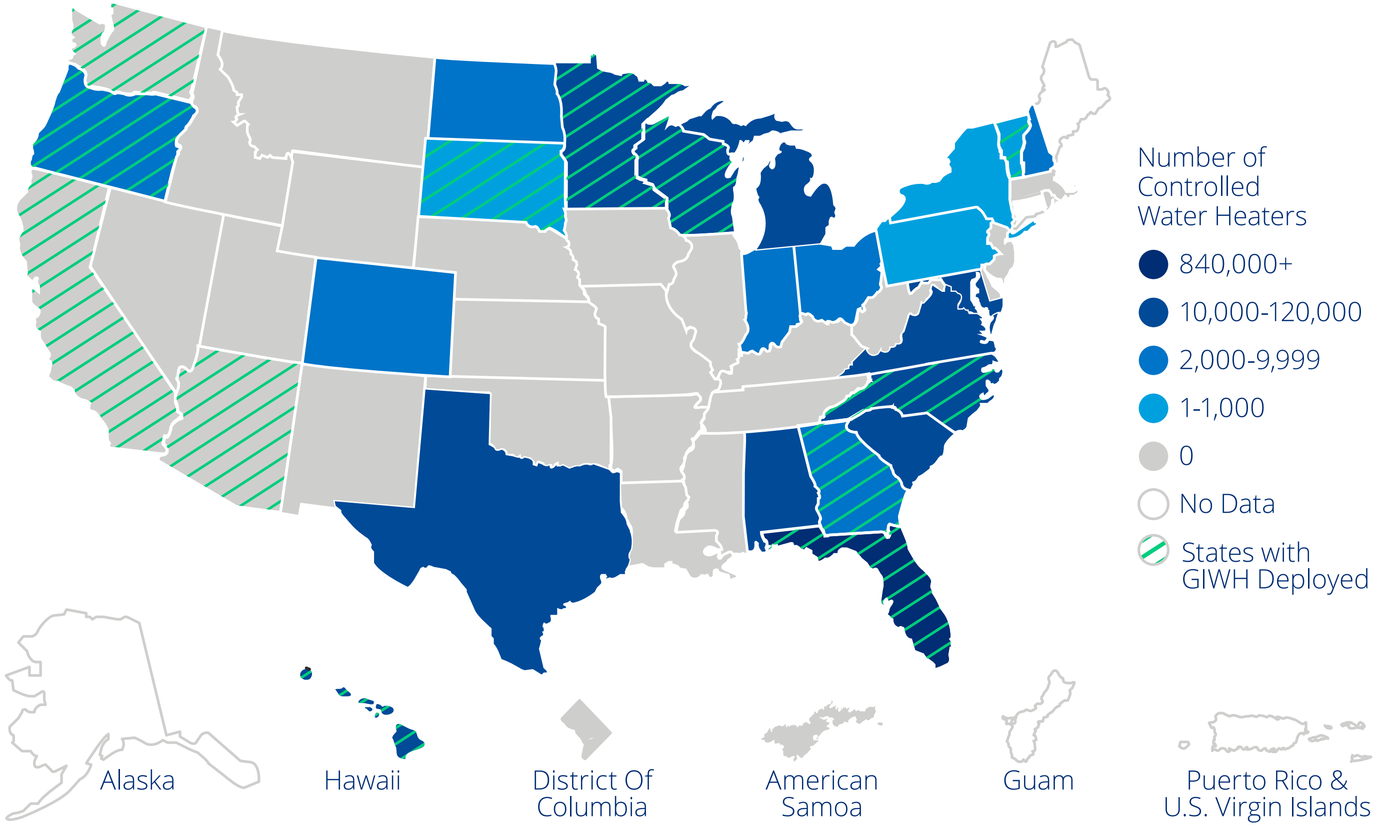
5 Bonneville Power Authority. (2019). Water heater innovation could boost NW renewable energy development. Retrieved from https://www.bpa.gov/news/newsroom/Pages/Water-heater-innovation-could-boost-NW-renewable-energy-development.aspx
6 EnergyHub. (2019). United Illuminating announces successful income-eligible water heater program in partnership with EnergyHub and Rheem. Retrieved from https://www.energyhub.com/blog/united-illuminating-der-program
7 Pacific Gas and Electric. (2019). WatterSaver Program: Behind-the-Meter Thermal Energy Storage Program Implementer. Retrieved from https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/purchasing-program/bid-opportunities/COA-RFP-WatterSaver-Program.pdf

MW = Megawatts-ac

Unlocking the potential of water heaters

A number of utilities with water heater programs are exploring the value of smart water heaters and wireless communication to control products through a switch. In addition, utilities and third-party aggregators have the opportunity to retrofit or replace existing water heaters with GIWHs.

Figure 8: 2018 Mass Market Water Heaters (Number of Devices)



Source: Smart Electric Power Alliance, 2019. Results from survey and interviews with industry experts.

MW = Megawatts-ac

Table 1: One-Way vs. Two-Way Water Heater Capabilities				
	Communication Capabilities	**Age of Technology**	**Benefits and Services**	**Limitations / Barriers to Adoption**
Traditional Water Heaters	One-way control	~30 years (established)	▪ Load-shifting: thousands of electric water heaters are connected to one-way load control devices, allowing utilities to shift load to off-peak hours. In this case, one-way electric water heaters act as thermal energy storage systems.	▪ Limited grid services. ▪ No visibility into unit-level performance. ▪ Do not allow customer-specific cold water prevention strategies. ▪ As systems grow older and reach end-of-life, utilities do not have the ability to track which systems respond during dispatched DR events.
Grid-Interactive Water Heaters (GIWH)	Two-way control	~5 years (nascent)	▪ Rapid, stackable services: frequency regulation, load shifting, load building, and ancillary services. ▪ Allow for dynamic grouping and dispatch of varying sized fleets of GIWHs to respond to circuit level contingencies. ▪ Provide data on customer usage habits, allowing utilities and 3rd party aggregators to maximize the available grid service capacity while minimizing negative impacts on customers.	▪ Technology adoption: delays are often encountered when introducing new technology programs. ▪ Consumer mindshare: behind-the-meter storage and smart thermometers are trendy and customer facing. Many customers are not aware of GIWHs and the benefits they offer. ▪ Accessibility: GIWHs and retrofit controllers are not readily available at commercial appliance stores.

Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

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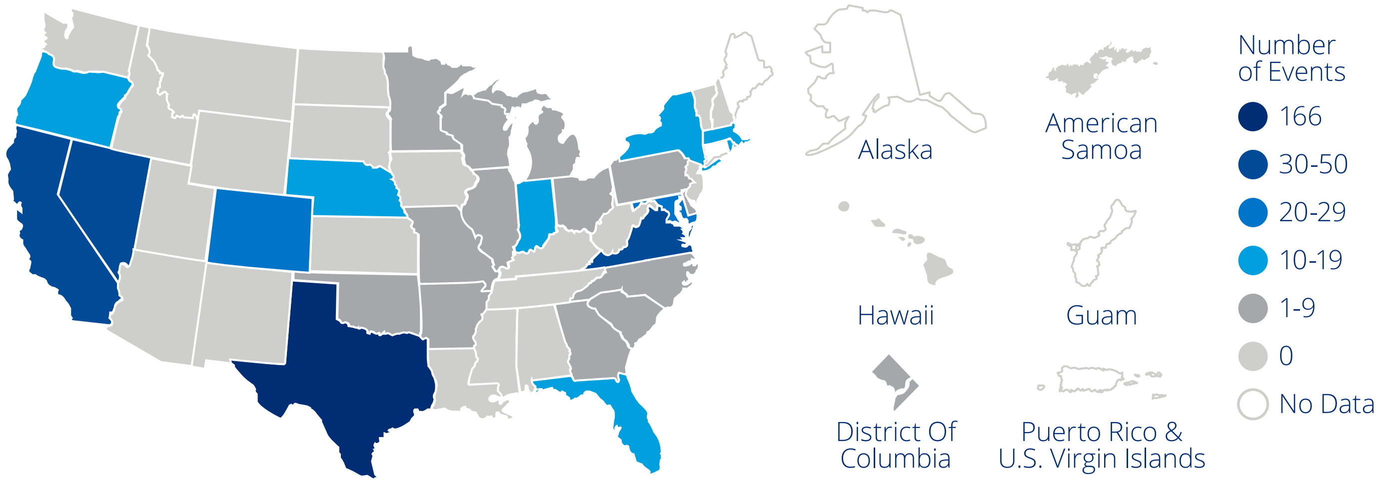
Thermostat Programs

Figure 9: 2018 Thermostat Program Summary

Enrolled Capacity: **1,042.7 MW**	Dispatched Capacity: **936.1 MW**

58 Utilities with Programs	**53** Utilities that Called an Event	**2.6** Hours Average Event Duration	**1.1** Million Customers Enrolled

Thermostat Events Called in 2018



Average Number of Events Called: **8.9**

Source: Smart Electric Power Alliance, 2019

This year's survey found that thermostat programs continue to be a popular utility option. Thermostat programs are largely fully implemented (82.5%), as opposed to in the piloting phase (17.5%). Additionally, Bring Your Own Thermostat (BYOT) business models are now the industry standard, and smart thermostats are prevalent throughout the country. These connected thermostats are capable of receiving DR control signals and sharing data with the utility.

Key Observations:

- Utilities use thermostat programs to serve four primary purposes: deferring generation capacity (20.6%), encouraging economical energy use (12.7%), deferring/replacing transmission and/or distribution capacity (11.1%), and peak shaving (11.1%).
- Thermostat programs will continue to expand, with 11 utilities reporting thermostat pilot programs and six utilities reporting full program implementation in 2019 or beyond.
  - Programs include a mix of thermostat technologies and delivery models, including: Wi-fi enabled/smart thermostats (84.8%), one-way communicating thermostats (8.7%), and mixed-metered gateways (6.5%).

MW = Megawatts-ac

Thermostat Program Highlights

Thermostats serve as the entry into the smart home and demand side management programs for utilities, with smart thermostats and BYOT programs becoming common utility offerings. As utilities have seen the successful implementation of these programs, some are now moving beyond the BYOT model to thermostat programs that incorporate precooling, other devices, or pair BYOT with energy efficiency. Additionally, utilities are exploring the intersection of thermostats with time-based pricing. These expansions on traditional thermostat programs show that utilities can successfully implement the BYO model as part of an orchestrated approach to DR.

In 2018, **Arizona Public Service (APS)** and **EnergyHub** launched “Cool Rewards”, a program that uses smart thermostats to strategically lower peak demand during summer DR events. The program incorporates pre-cooling optimized for time-of-use pricing and also maintains customer comfort during events by shifting load to times when solar energy is abundant. Along with “Cool Rewards”, APS and EnergyHub partnered on a program that uses a DR and energy storage suite to deliver peak demand reduction, load shifting and renewables matching. Using EnergyHub’s Mercury platform, APS can enroll, monitor, and manage residential batteries in the Storage Rewards program, as well as grid-interactive water heaters in the Reserve Rewards program. In addition to its DR and energy storage aggregations, APS will manage residential and commercial solar fleets. This suite of managed technologies is designed for peak demand reduction, load shifting and renewables matching, solar fleet operations, and advanced load and capacity forecasting based on machine learning. By modernizing its demand side management programs, APS is able to use these services year round and multiple times a day, and integrate DERs.[8]

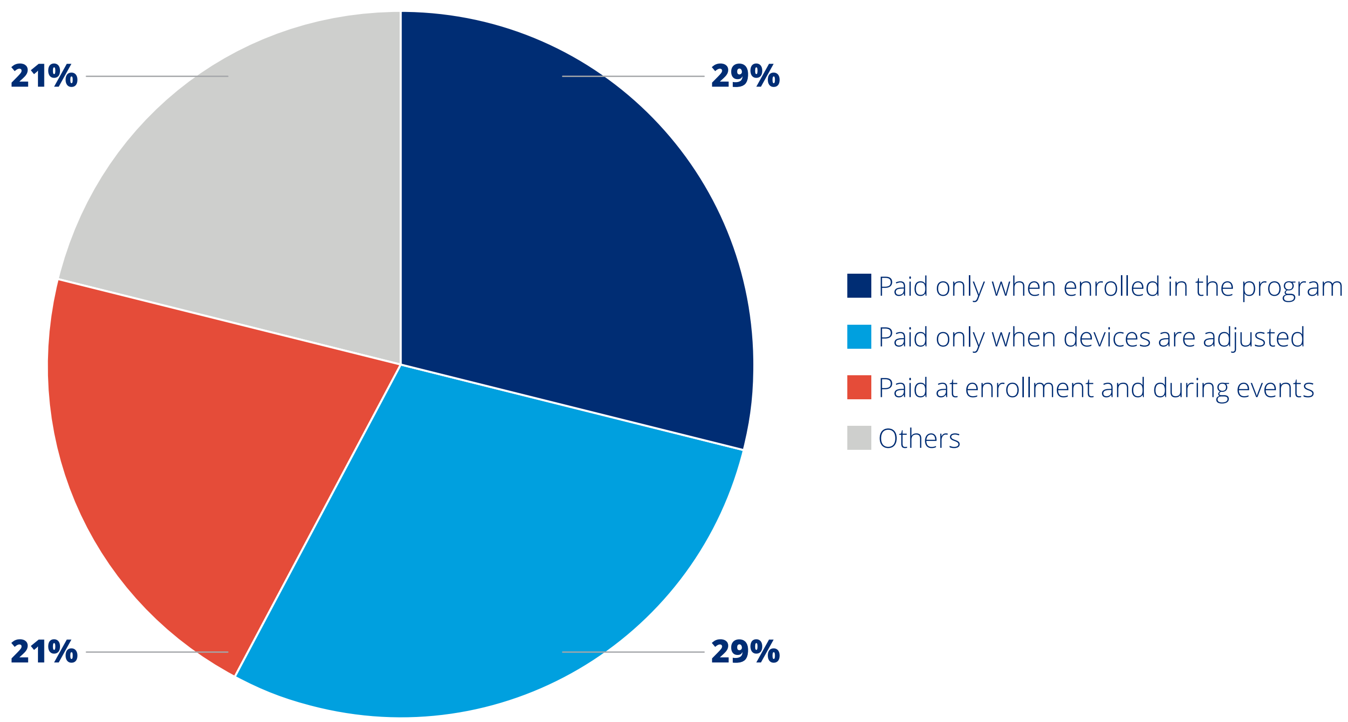
Pepco and **Delmarva Power** are working to bridge energy efficiency (EE) programs and DR programs. Within these utilities, the EE and DR teams collaborated to leverage smart thermostats installed in their territory. The companies offer customers the opportunity to simultaneously enroll in a new energy efficiency program, “Thermostat Optimization Program” (TOP), and participate in their DR program, “Energy Wise Rewards™”, through a Bring Your Own Device (BYOD) option.

8 Energy Hub. (2018). Arizona Public Service chooses EnergyHub’s Mercury DERMS to deliver innovative grid-edge DER management strategies. Retrieved from: https://www.energyhub.com/blog/arizona-public-service-energyhub-mercury-derms

MW = Megawatts-ac

Smart Electric Power Alliance

Figure 10: Rewards for Participation in Peak Load Program (Q4/18)



"Q7890. In which of the following ways are you rewarded for participating in the peak load control program?"
Among U.S. BB HHs Participating in Peak Load Control Program, n=336, + 5.35%

Rewarding Participation

Recruiting, engaging, and incentivizing customers in DR programs is critically important for increasing participation in peak time programs. As BYOD programs gain popularity, they have the potential to reward participation in different ways. Based on a Parks Associates survey of 10,000 U.S. broadband households and 336 people who participate in peak load programs, it appears that programs are almost evenly split in methods for incentivizing customer participation in peak load events. While there appears to be no majority method for rewarding participation, it should be noted that, between devices, program structures, and rewards, the industry is becoming increasingly diverse in its offerings.

MW = Megawatts-ac

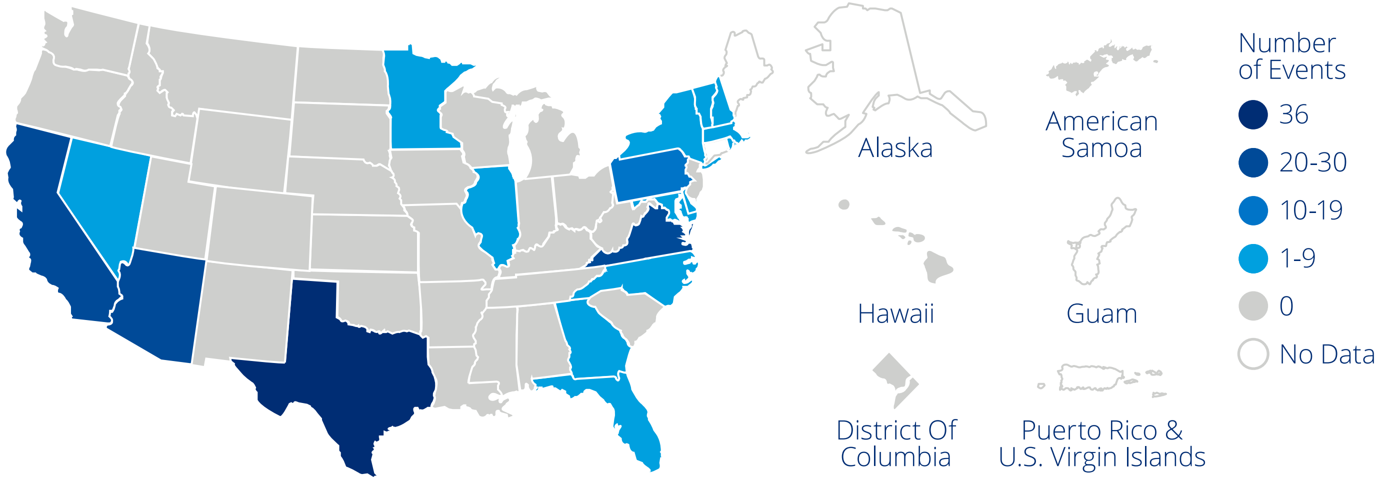
Behavioral Programs

Figure 11: 2018 Utility Behavioral Program Summary

Enrolled Capacity: **785.1 MW**

54 Utilities with Programs	**27** Utilities that Called an Event	**3.6** Hours Average Event Duration	**2.7** Million Customers Enrolled

Behavioral Programs Events Called in 2018



Average Number of Events Called: **7.1**

Source: Smart Electric Power Alliance, 2019

Behavioral DR, as traditionally understood, refers to programs that encourage or incentivize participation in peak events, through direct communication or education. Today, utilities are using some of these traditional communication methods to encourage participation in time of use (TOU) programs.

For the purposes of the survey, SEPA asked utilities to identify dispatchable DR events. Some utility programs may use messaging to encourage participation in TOU programs, thus including these as events. SEPA's survey captured legacy behavioral DR programs, as well as programs that use behavioral methods such as messaging to encourage participation in some time-based programs.

Key Observations:

- Of the utilities that listed a primary program purpose for calling behavioral DR programs, 66.7% reported peak shaving as the main reason for offering the program.
- Survey results indicated 54 active behavioral programs with 47 fully implemented and 7 that are in pilot phases. Additionally, two utilities noted that they have programs set to begin in 2019 and two planned for 2019.

MW = Megawatts-ac

Table 2: Approaches to Behavioral Demand Response	
Behavioral DR can encompass different methods of dispatching load. Methods for signaling events, integrating customer experience across new platforms, and managing customer communications to encourage participation are changing as new devices are being introduced into customers' homes. Successful behavioral DR programs have employed various methods, such as an opt-out approach (versus opt-in) or using existing customer interfaces and apps, to encourage customer participation. The following programs illustrate the different approaches to behavioral DR and reducing peak demand.	
Traditional behavioral demand response (event-based)	**Time-based behavioral demand response (habitual)**
Oracle's "SmartEnergy Rewards", a peak time rebate program, shows how traditional behavioral DR can be successfully deployed. This program has been implemented at multiple utilities. Its implementation at **Baltimore Gas and Electric (BGE)** is the largest digital DR program in the U.S., with 1.1 million homes enrolled in peak time rebates, over 70% participation in peak savings, and 300 MW cleared on the PJM capacity market. BGE notifies customers the day before a savings event and participating customers receive a bill credit. The program automatically enrolls customers with installed smart meters (making it an opt-out program), and combines a peak rewards program that uses traditional DR with an AC switch or thermostat that pays a small fee for participation, with a smart energy rewards program that is behavioral and pays out as a peak rebate. Customers can participate in both and claim the greater benefit.	Along with their SmartEnergy Rewards program, Oracle's "Behavioral Load Shaping" program uses "Time of Use Coach" and "High Bill Alert" to personalize weekly update emails to customers showing peak usage to prevent bill shock. The program aims to reduce peak demand and increase customers' satisfaction and engagement with TOU rates, making them less likely to opt out. The program began enrolling customers in April 2019 and is currently in pilot phase; participating utilities include: **Baltimore Gas and Electric**, **Delmarva Power**, and **Pepco**.

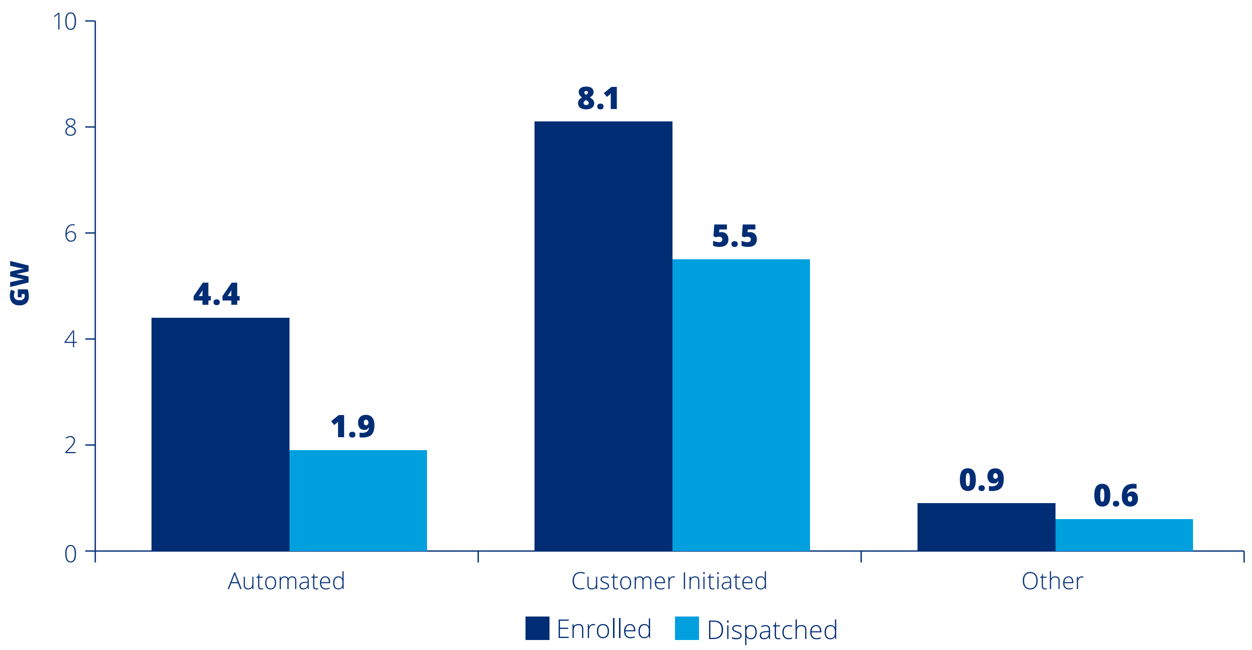
Source: Smart Electric Power Alliance, 2019

MW = Megawatts-ac

C&I Demand Response Programs

C&I programs contributed 13.3 GW of enrolled DR capacity in 2018, representing 64.9% of the total enrolled capacity in 2018.

Figure 12: 2018 Commercial and Industrial Demand Response Enrolled and Dispatched Capacity (GW)



Source: Smart Electric Power Alliance, 2019. N=190 Utility Survey participants.

Table 3: 2018 Utility Commercial and Industrial Program Summary

	Automated	Customer Initiated	Other
Number of Utilities with Programs	60	78	32
Number of Utilities that Called Events	47	49	10
Total Number of Customers Enrolled	72,353	31,397	1,825
Average Number of Events Called	13.7	7.4	6.1

Source: Smart Electric Power Alliance, 2019

Key Observations:

- C&I DR programs serve three primary purposes: defer or replace generation capacity (31.8%), emergency load management/reduction (22.4%), and to encourage economical energy use (14.1%).
- Six utilities in Pennsylvania have utilized customer initiated DR programs to meet requirements for demand reduction established by the Pennsylvania Public Utility Commission in 2008.
- Other C&I programs accounted for in this survey include those that do not fall under "automated" or "customer initiated" such as irrigation control.

MW = Megawatts-ac

C&I Program Highlights

In 2019, **Ameren (Missouri)** partnered with **Enel X** to finalize its Business Demand Response Program. The partnership will allow Enel X to manage Ameren's C&I DR porfolio. The program will reduce load during times of peak demand, and has delivered 25 MW of DR resources so far in 2019, with a projected demand reduction capacity of 100 MW from the utility's C&I customers for the 2019-2021 program period.[9] In addition to helping reduce peak demand, this program will provide capacity resources to the MISO transmission system.

In 2018, **Eversource** introduced a new software platform that has allowed the utility to integrate a variety of technologies to address C&I peak demand and provide customers with solutions specific to their needs. Eversource has implemented open communication protocols to allow for easy integration of a diverse range of devices (smart thermostats, battery storage, etc.). Utilizing this approach, Eversource successfully reduced regional peak demand by nearly 9 MW in 2018.

C&I Non-Wire Alternatives

C&I programs represent an important option for utilities that are considering non-wire alternatives (NWA) projects. In a recent NWA report from SEPA, E4TheFuture, and PLMA, three of the ten NWAs that were highlighted leveraged C&I DR to defer traditional transmission and distribution (T&D) upgrades.[10]

- **Bonneville Power Authority**'s South of Allston project explored the local impacts of a new $1 billion transmission line, but the utility ultimately chose to implement a more flexible and scalable NWA solution. One of the two solutions in the project portfolio involved managing large C&I customer end-user demand.
- **Consumers Energy**'s Swartz Creek Energy Savers Club was able to successfully reduce demand through increased program participation. Although C&I customers were challenging to recruit, commercial lighting programs offered the majority of savings along with residential DR programs.
- **Southern California Edison** solicited offers to meet long-term local capacity requirements (LCR) resulting from nuclear and natural gas generation plant closures. **STEM** was awarded the project in 2016 and has integrated over 100 C&I battery storage systems to meet the LCR by operating as a virtual power plant and meeting critical peak capacities.

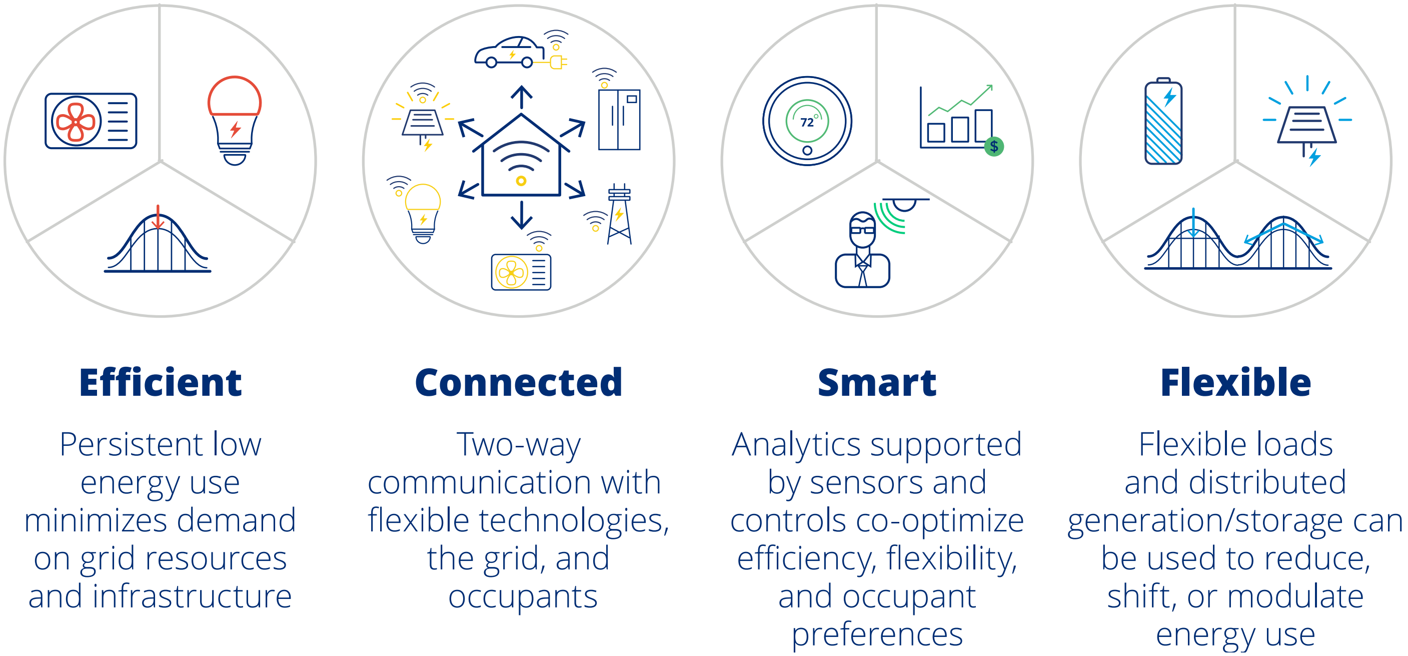
9 ENEL X. (2019). Enel X Signs 100 MW Demand Response Agreement with Ameren Missouri. Retrieved from https://www.enelx.com/n-a/en/news-media/all-press/enel-x-signs-100mw-demand-response-agreement-ameren-missouri
10 SEPA (2018). Non-Wires Alternatives: Case Studies from Leading U.S. Projects. Retrieved from https://sepapower.org/resource/non-wires-alternatives-case-studies-from-leading-u-s-projects/

MW = Megawatts-ac

Grid-Interactive Efficient Buildings

With the growing number of DERs interconnected on the grid, C&I demand flexibility is as important as ever. Grid-interactive efficient buildings play an important role by integrating energy-efficient measures like high-quality walls, windows, and lights that reduce peak demand with grid connectivity to respond to grid needs and integrate DERs. As shown below in Figure 13 , grid-interactive efficient buildings can provide efficient, connected, smart, and flexible power to provide generation and transmission services as well as ancillary service benefits.

Figure 13: Characteristics of Grid-Interactive Efficient Buildings



Source: Department of Energy. (2019). Grid-Interactive Efficient Buildings. Retrieved from https://www.energy.gov/sites/prod/files/2019/04/f61/bto-geb_overview-4.15.19.pdf.

Table 4: Potential Benefits/Avoided Costs Provided by Commercial and Industrial Demand Flexibility

Grid Services	Potential Benefits/Avoided Costs
Generation Services	The deferment/replacement of generation capacity has become an important benefit for utilities integrating DR on a C&I level.
Transmission & Distribution Services	DR offers an opportunity as a Non-Wire Alternative (NWA) to defer or avoid the need for traditional transmission and distribution (T&D) investments or reduce constraints along the grid.
Ancillary Services	C&I demand flexibility can offer the important role of regulating frequency and voltage as well as providing spinning reserves through reduced demand over short periods of time.

Source: Department of Energy. (2019). Grid-Interactive Efficient Buildings. Retrieved from https://www.energy.gov/sites/prod/files/2019/04/f61/bto-geb_overview-4.15.19.pdf.

MW = Megawatts-ac

Demand Response Policy Updates

Time-Varying Rates

Many utilities offer time-of-use (TOU) rate options for customers as a mechanism to shift energy use from periods of peak system demand to off-peak periods. While the majority of these are offered on an opt-in basis, some utilities are implementing default, or opt-out, TOU rates. Recent state activity related to TOU rates includes:

- **California:** Responding to the California Commission's decision to reform residential rate structures, the state's major IOUs have begun transitioning residential customers to default TOU rates aiming to complete the transition by the end of 2019.
- **Maryland:** The Public Service Commission approved TOU rate pilots in 2018, as part of the state's PC 44 grid modernization proceeding.
- **Michigan:** The Michigan Public Service Commission directed DTE Electric to begin implementing default TOU rates in 2018, and approved default residential TOU rates for the utility in May 2019.
- **New Hampshire:** A working group is developing TOU rate pilots in New Hampshire that will help to inform future changes to net metering rules.
- **Virginia:** Legislation enacted in March 2019 directs Dominion Energy to convene a stakeholder group to produce TOU rate recommendations.

Innovative Rate Designs

Some utilities are piloting new rate structures beyond time-varying rates, including those that contain critical peak pricing, demand charges, subscription rates, and time-varying rates designed specifically to encourage electric vehicle charging.

Table 5: Innovative Rate Design Actions

Arizona	Arizona's three investor-owned utilities offer a pilot "R-TECH" rate to residential ratepayers with certain customer-sited resources. The tariff features time-varying rates and two demand charges.
Minnesota	Xcel Energy filed a proposal for a new residential electric vehicle subscription rate in February 2019, which would provide participants with unlimited off-peak charging at home.
North Carolina	Duke Energy Carolinas proposed dynamic price pilots in April 2019, pursuant to a Commission order. The pilots include critical peak pricing and daily peak pricing for residential and small commercial customers.

Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

MW = Megawatts-ac

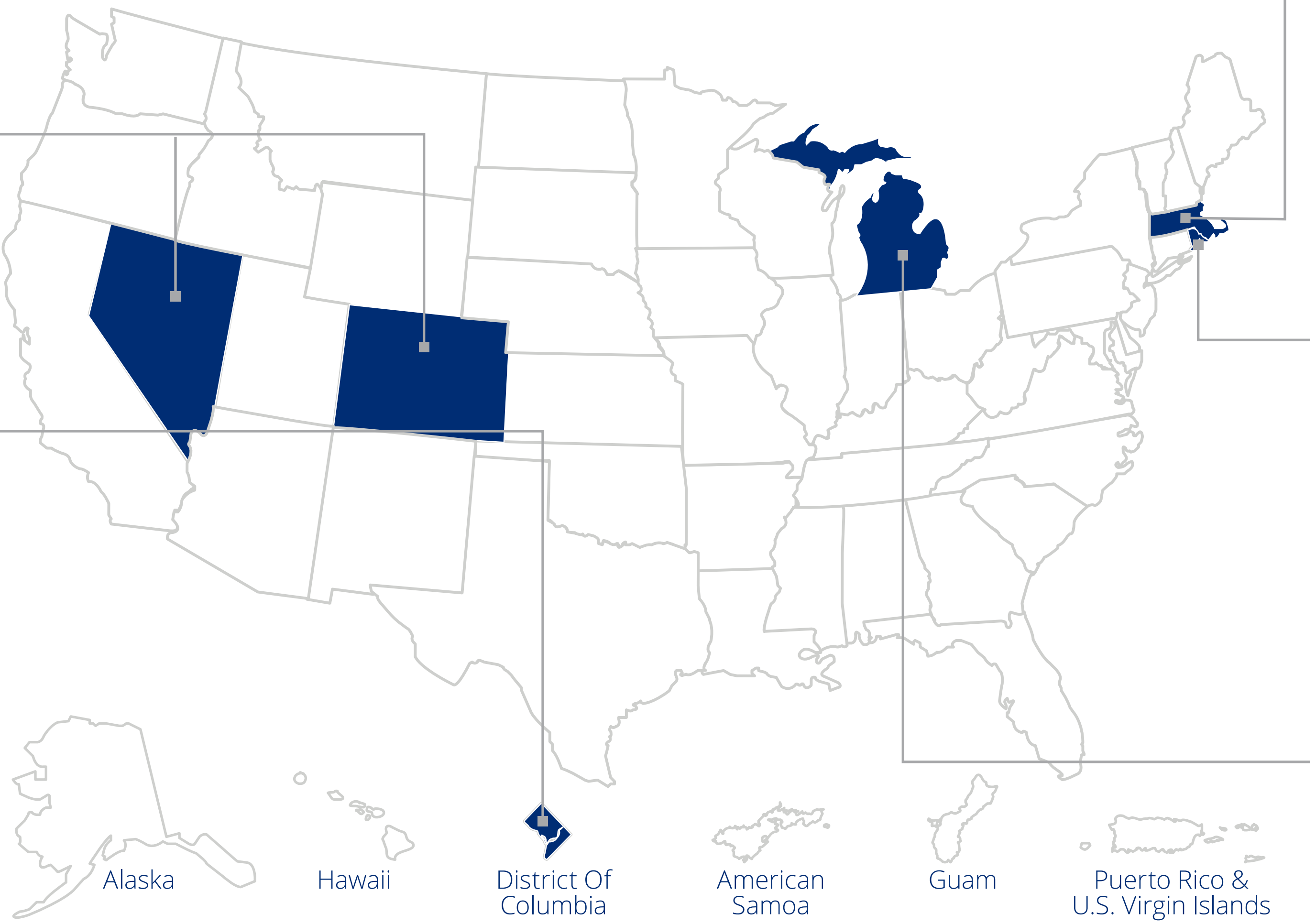
NC CLEAN ENERGY TECHNOLOGY CENTER DSIRE insight Smart Electric Power Alliance

Demand Response Policy Activity

Distribution System Planning and Non-Wires Alternatives: Colorado legislators enacted S.B. 236 in June 2019, directing the Public Utilities Commission to develop distribution system planning rules and a methodology to evaluate the use of distributed energy resources, including DR, as NWAs. In October 2018, the Public Utilities Commission of Nevada adopted distributed resource planning rules encompassing DR resources.

Energy Efficiency and Demand Response Programs: The Clean Energy DC Omnibus Amendment Act of 2018 requires the DC Commission to establish a working group to guide the development of utility-administered EE and DR programs to primarily benefit low and moderate-income residential ratepayers. The Act authorizes the Commission to approve efficiency and demand reduction programs and new cost recovery mechanisms proposed by utilities.

Figure 14: States with Recent Demand Response Policy Activity



Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

Clean Peak Standards: Massachusetts lawmakers adopted the first Clean Peak Standard in the country in 2018, which will allow DR resources to be used for compliance. Additionally, a straw proposal was released in 2019, which specifies the types of resources that may be used for compliance and designates four hours for each season as peak periods.

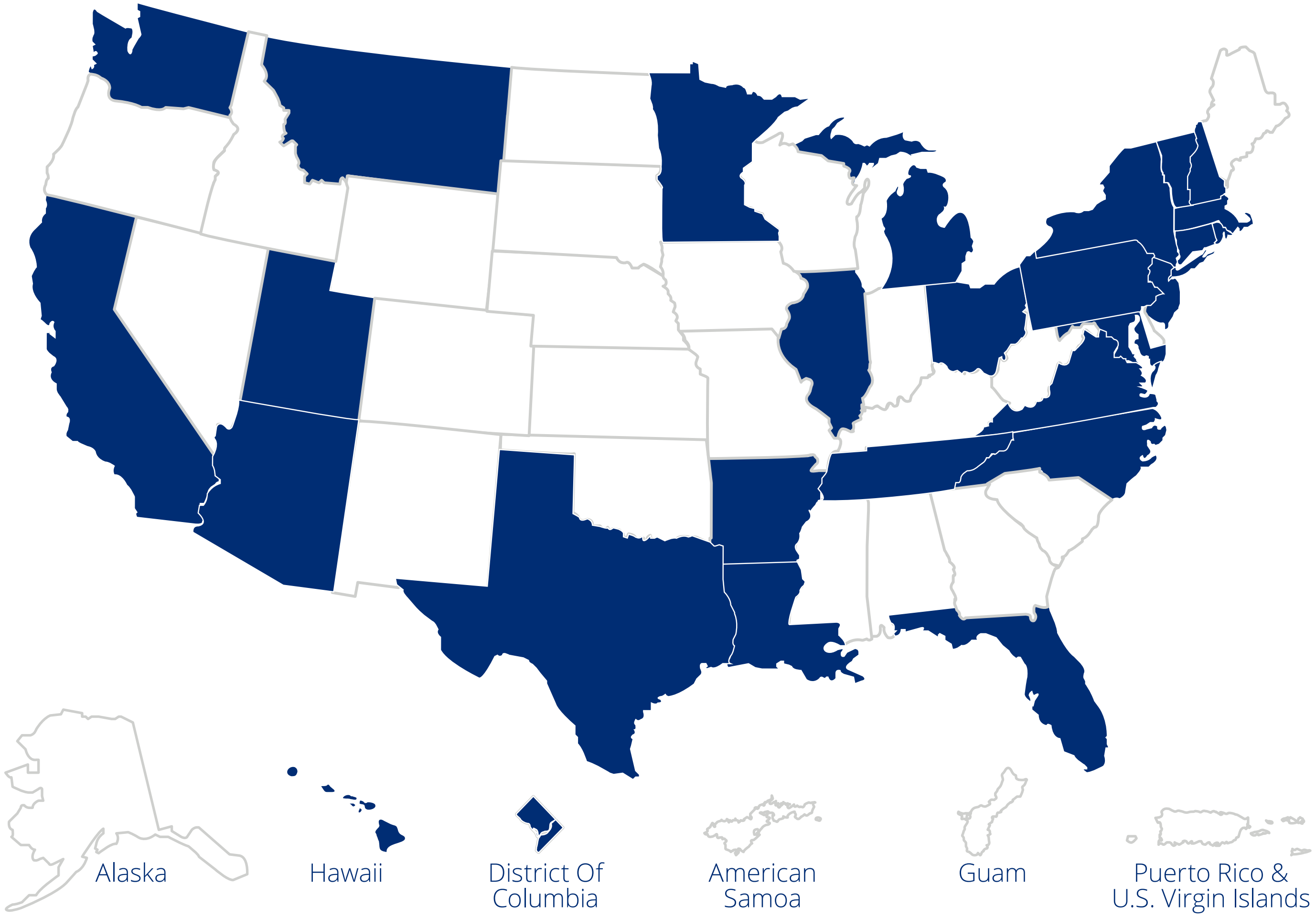
Performance Incentive Mechanisms: In an August 2018 decision, Rhode Island regulators approved a new performance incentive mechanism for National Grid based on capacity savings. In Massachusetts, National Grid proposed a new performance incentive mechanism based on peak reduction in November 2018.

Demand Response Aggregation: In November 2018, the Michigan Public Service Commission opened a proceeding to investigate DR aggregation issues.

MW = Megawatts-ac

Customer Data Access Policies

Figure 15: States Recently Considering Data Access Policies



Source: DSIRE Insight, NC Clean Energy Technology Center, 2019

At least 26 states and DC have considered rules for access to customer energy usage since the start of 2018. Access to such data could provide increased opportunities for DR.

Recent State Activity:

Recent state activity addresses customer access to their energy usage data, allowing customers to designate third parties to access their data, and providing access to aggregated energy usage data.

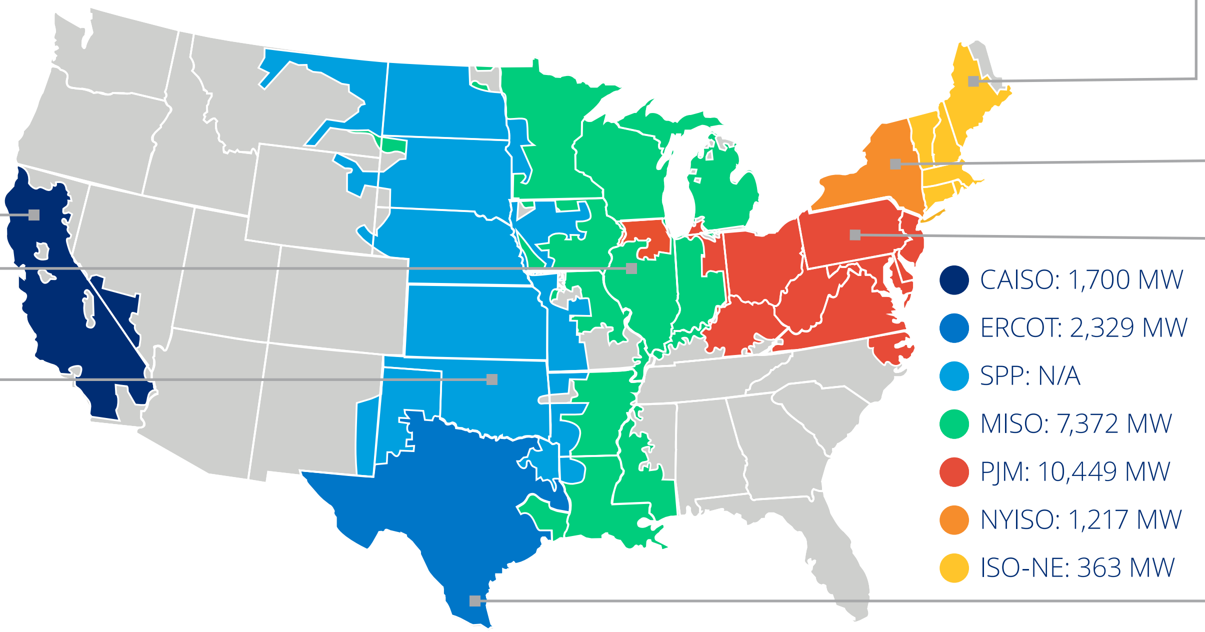
- **Hawaii:** Lawmakers enacted a bill in May 2019 giving ratepayers access to their consumption and production data and the ability to authorize third-party access.
- **Montana:** H.B. 267, enacted in April 2019, requires that customers have access to usage data collected by advanced metering infrastructure and have the authority to designate a third party to gain access. The bill also allows utilities to disclose aggregated and anonymized usage data.
- **North Carolina:** The North Carolina Utilities Commission opened a new proceeding on customer data access rules in February 2019.
- **Ohio:** Following completion of the PowerForward grid modernization investigation, regulators opened a new proceeding on data and the modern grid.
- **Virginia:** Lawmakers enacted legislation in March 2019 directing the State Corporation Commission to convene a data access stakeholder group.

MW = Megawatts-ac

Demand Response in Wholesale Power Markets

- **California Independent System Operator (CAISO): 1,700 MW** of total available capacity from reliability DR resources in 2017 was integrated into the CAISO market.[11] This represented 3.5% of the 2018 resource adequacy capacity for CAISO.
- **Midcontinent Independent System Operator (MISO): 7,372 MW** of DR was cleared in the 2019-2020 planning resource auction results for meeting resource adequacy requirements. This represented 5% of the 2019 capacity for MISO. Note however that DR in the MISO market is primarily retail DR with utilities and is not actively traded in wholesale power markets, unlike the other ISOs/RTOs.[12]
- **Southwest Power Pool (SPP): N/A**

Figure 16: Demand Response Capacity by Regional Transmission Organization and Independent System Operator



Source: Navigant Research, 2019

Navigant's Methodology for ISO and RTO DR capacity

These numbers are based on publicly available data from the ISOs and RTOs and communication with ISO and RTO members. For PJM, NYISO, and ISO New England, the numbers shown are capacity market obligations. For MISO, ERCOT, and CAISO, they are a combination of the enrollment in the different DR programs that each RTO offers.

- **ISO New England: 363 MW** of DR assets had capacity obligations in the ISO-NE market in May 2019. This represented 1.4% of the 2019 capacity for ISO-NE.[13]
- **New York Independent System Operator (NYISO): 1,217 MW** of capacity was enrolled (as of June 2019) in the reliability-based program, Installed Capacity-Special Case Resources (ICAP/SCR), offered by NYISO. This represented 3% of the 2019 capacity for NYISO.[14]
- **PJM Interconnection (PJM): 10,449 MW** of DR is participating in the PJM market for the 2019/20 delivery year, which represents 6% of the total PJM capacity in that year.[15]
- **Electric Reliability Council of Texas (ERCOT): 2,329 MW** in combination awarded in ERCOT's Responsive Reserve Service (RRS) and procured in Emergency Response Service (ERS) programs by the end of 2018.[16] This represented 3% of the 2018 capacity for ERCOT.

11 California ISO. (2018, page 42). Annual Report on Market Issues and Performance. http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance.pdf
12 MISO. (2019). 2019/2020 Planning Resource Auction (PRA) Results. This was the total amount of Demand Response cleared in the MISO market in 2019-2020. Retrieved from https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf
13 ISO-NE. (2019). Demand Resources Working Group Monthly Report. Retrieved from https://www.iso-ne.com/committees/markets/demand-resources/
14 NYISO. (2019). Special Case Resources Monthly Report. Retrieved from https://www.nyiso.com/documents/20142/4341980/2019-06-SCR-Monthly-Report-June-After-Close-of-Partial-Sales.pdf
15 PJM. (2019). 2019 Demand Response Operations Markets Activity Report: September 2019. Retrieved from https://www.pjm.com/-/media/markets-ops/dsr/2019-demand-response-activity-report.ashx?la=en
16 ERCOT. (2018). 2017 Annual Report of Demand Response in the ERCOT Region. Retrieved from http://www.ercot.com/content/wcm/lists/94805/2017_Annual_Report_of_Demand_Response_in_the_ERCOT_Region.docx

MW = Megawatts-ac

Table 6: Regional Transmission Organization/Independent System Operator Updates

RTO/ ISO	Update
CAISO	▪ DR providers or aggregators and retail customers can participate in day-ahead and real-time energy markets, and the ancillary services market. ▪ 2019 Demand Response Auction Mechanism (DRAM) for bidding retail DR into the wholesale market reported a total bid of 167 MW for both residential and non-residential DR. DRAM auctions are conducted by utilities, but DRAM resources are required to bid into the CAISO market. ▪ CAISO's DR availability assessment hours changed to 4pm-9pm year round. This change from mid-day will help flatten the neck of the duck curve in the evening when solar goes offline and demand increases.
ERCOT	▪ Loads controlled by high-set, under-frequency relays continue to dominate the number and capacity volume of DR resources that participate in the ancillary service market (Responsive Reserve). ▪ Prior to summer 2019, experts predicted that ERCOT's reserve margin would drop to a record low (7.4%). If ERCOT's capacity reserve drops too far below its target, the market's scarcity pricing mechanism can trigger, meaning higher prices available for DR participation in the market. ▪ In August 2019, ERCOT called an energy emergency alert twice in one week as capacity reserves dipped below ERCOT's set reserve margin.
MISO	▪ DR is eligible to provide energy, capacity, and ancillary services; the majority of participation is from utilities. ▪ The total amount of DR cleared in MISO's 2019-2020 Planning Resource Auction (PRA) was almost 6% greater than the previous year's amount. This change was due to an increase in the planning reserve margin requirement, a decrease in supply, and changes in market participants' offer behavior. The current DR amount in the PRA represents 5% of MISO's total planned resource for 2019-2020.

Table 6: Regional Transmission Organization/Independent System Operator Updates

RTO/ ISO	Update
ISO-NE	▪ The implementation of the ISO-NE price-responsive demand construct has led to several key changes for 2019 in its DR programs: (1) DR programs are now dispatched based on economic (instead of emergency) conditions, (2) DR is now considered fast-acting and must be dispatched within 30 minutes of the grid's call for curtailment, and (3) DR resources can be offered into both day-ahead and real-time energy markets.
PJM	▪ In late 2018 PJM approved a summer-only DR proposal to accommodate utility air conditioning-focused programs that could be ineligible for annual capacity payments. Rather than earning capacity payments, the reliability requirement will be lowered by the MW committed in the program, and the utility will receive an avoided capacity cost. This change will take effect for the 2019 capacity auction for the 2022/23 Delivery Year. ▪ In 2019, a new rule allows customers to contribute different seasonal load values in the capacity market if their curtailment service provider (CSP) can find an offsetting capacity match from another DR customer within that same load zone. ▪ In June 2019, FERC rejected a proposal by PJM that would have required DR resources to participate year-round.
NYISO	▪ In 2018, NYISO proposed changes to the capacity market dictating how long a resource must be able to run to be eligible to receive the full value of capacity. ▪ NYISO initially proposed that resources would need to be able to run for 8-hours in order to obtain full capacity value. But, it soon modified its proposal following feedback from DR and energy storage providers. NYISO's modified proposal created an incremental scale of duration times and the corresponding portion of the full value of capacity a resource would receive. The modified proposal also considers the capacity (MW) of each resource.

Source: Navigant Research, 2019

Challenges and Opportunities

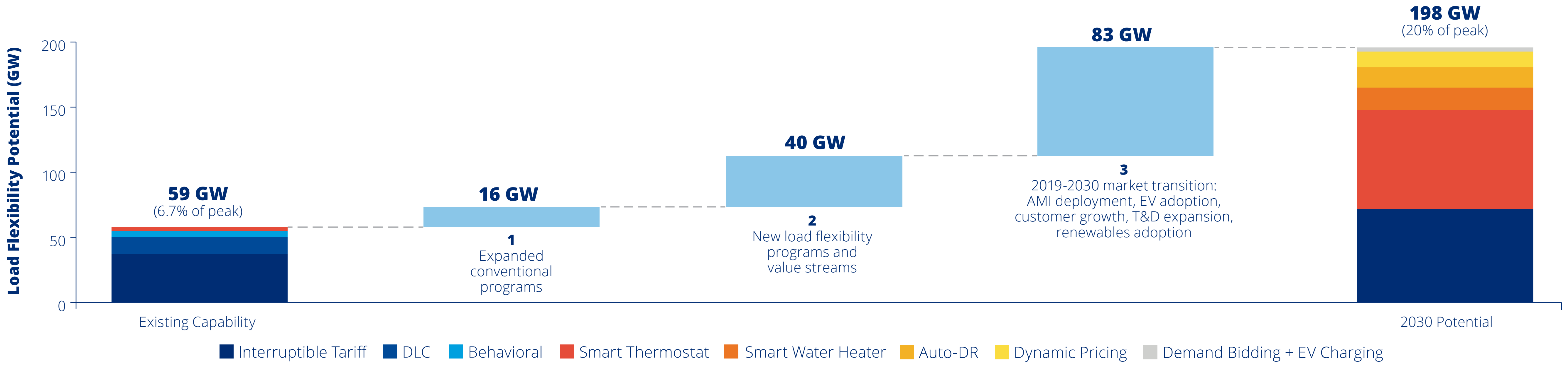
- Turnover of FERC Commissioners, and lack of replacements and quorum, may delay approval of RTO market reforms, including decisions on DER and energy storage specifically.
- Capacity and energy market prices have stabilized and even decreased in many markets as low-cost renewables enter the market, which may lower the incentives for DR to participate.
- Many RTOs are investigating ways to address DR and DER as a more-diverse set of resources enter the market. This includes determining mechanisms to limit and/or accommodate seasonal resources like air conditioning-based DR, and hours of run-time limits for resources like energy storage.
- RTOs are devising more effective processes to aggregate DR and DER resources to enhance market participation opportunities as individual contributors shrink (at the residential level and for electric vehicles) and for pairing summer and winter resources to create annual resources.
- Value-stacking potential of wholesale and retail DR programs is growing in importance as utilities build up DR programs for distribution-level purposes where customers can participate in both types of programs/markets concurrently.
- The growth of intermittent renewable capacity like solar and wind may require new types of grid flexibility services for DR.

MW = Megawatts-ac

Demand Flexibility and Advanced Applications of Demand Response

In a recent study, The Brattle Group identified 200 GW of economically-feasible load flexibility potential in the U.S. by 2030.[17] This potential equates to 20% of 2030 U.S. peak load levels. The benefits of this load flexibility could save the U.S. energy sector more than $15 billion per year by 2030. **Load flexibility** refers to load being managed to provide value beyond total system peak demand reduction, such as geographically targeting demand reductions, load building, and system balancing.

Figure 17: U.S. Cost-Effective Load Flexibility Potential by 2030



Source: The Brattle Group, 2019

17 The Brattle Group. (2019). The National Potential for Load Flexibility. Retrieved from https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf

MW = Megawatts-ac

The Brattle Group identified three main factors that contribute to the projected growth in DR capacity:

1. **Expansion of Conventional Programs (potential increase over existing capability: 16 GW [27%])**
   - By expanding conventional programs through increased customer marketing and outreach, altering program regulations, and improving incentive measures, DR programs can see increased enrollment and capacity.
   - Conventional programs offer value due to their ability to address peak load concerns by leveraging existing program infrastructure.
2. **New Load Flexibility Programs (potential increase over existing capability: 40 GW [16%])**
   - Managing load through load flexibility programs, such as adopting advanced consumer technologies like smart thermostats and dynamic pricing, has the potential to increase DR capacity.
   - Load flexibility programs introduce new value streams and utilize emerging load control technologies and load sources.
3. **Market Transition Impacts from 2019 to 2030 (potential increase over existing capability: 83 GW [140%])**
   - Increased adoption of advanced metering infrastructure, EVs, smart thermostats, and other smart technologies is driving more participation in load flexibility programs.
   - Acceleration of renewable energy generation and associated generation variability increases the need for ancillary services that load flexibility programs can provide.
   - Non-wires alternatives will also see growing opportunity due to a need to expand and modernize T&D systems.
   - These developments justify greater customer participation and expansion of load flexibility programs.

Case Study: Xcel Energy Carbon Reduction Efforts

Xcel Energy announced in 2018 that it would deliver 100% carbon-free electricity to customers by 2050, and committed to reducing carbon emissions by more than 80% in their eight upper midwest customer states by 2030. Carbon reduction and electrification are supported through the incorporation of DR, as it can be used to address fluctuating power and load supplies.

The Brattle Group and Xcel Energy recently explored how DR can help meet these carbon reduction goals by expanding the impacts of cost-effective DR and load flexibility. They found that DR potential would increase by at least 37% by broadening conventional DR programs and would increase by an additional 18% through implementation of load flexibility programs.[18]

18 The Brattle Group. (2019). The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory. Retrieved from https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b10FBAE6B-0000-C040-8C1D-CC55491FE76D%7d&documentTitle=20197-154051-03

MW = Megawatts-ac

Going Beyond "DR 1.0":

In SEPA's 2017 Demand Response Market Snapshot, the evolution of DR along a DR 1.0, 2.0, and 3.0 framework was introduced, pulling from Peak Load Management Alliance's original model.[19] Figure 18 illustrates how Brattle's assessment of load flexibility market potential fits into this framework.

Figure 18: Load Flexibility Market Potential and Value

		Generation Capacity Avoidance	Reduced Peak Energy Costs	System Peak Related T&D Deferral	Targeted T&D Capacity Deferral	Load Shifting/ Building	Ancillary Services	
DR 1.0	**Direct Load**	■	■	■	■			Traditional DR (e.g., DR 1.0) typically includes one-way communication devices and is called upon less frequently during peak events.
	Interruptible Tariff	■	■	■				
	Demand Bidding	■	■	■		■		
	Time-of-Use (TOU) Rates	■	■	■				
DR 2.0 → DR 3.0	**Dynamic Pricing**	■	■	■				The DR industry is evolving to encompass 2.0 attributes (i.e., two-way communication devices, shifting of loads, more frequency and voltage regulation). Utilities and solution providers are starting to approach grid services with a technology agnostic lens, increase automation, and orchestrate DERs together to provide grid flexibility. Thus bringing us into the era of DR 3.0.
	Behavioral DR	■	■	■	■			
	Smart Thermostat	■	■	■		■		
	Timed Water Heating	■	■	■		■	■	
	EV Managed Charging	■	■	■	■	■	■	
	Ice-Based Thermal Storage	■	■	■	■	■		
	C&I Auto-DR	■	■	■	■	■	■	

DR 1.0: Utilities, through customer notifications or one-way communication load-control devices, focus mostly on demand mitigation during constrained peak.
DR 2.0: Uses bilateral communications, and greater locational capabilities to shift loads and provide frequency and voltage regulation services on a more automated level.
DR 3.0: Integrates DR into the larger ecosystem of DERs. Along with other DERs, DR can provide services to the grid, be called upon regularly, and is orchestrated across technologies.

Source: Smart Electric Power Alliance and The Brattle Group, 2019

19 Peak Load Management Alliance. (2017). Evolution of Demand Response in the United States Electricity Industry. Retrieved from http://www.peakload.org/default.asp?page=DefiningEvolutionDR.

MW = Megawatts-ac

Advanced Applications of DR

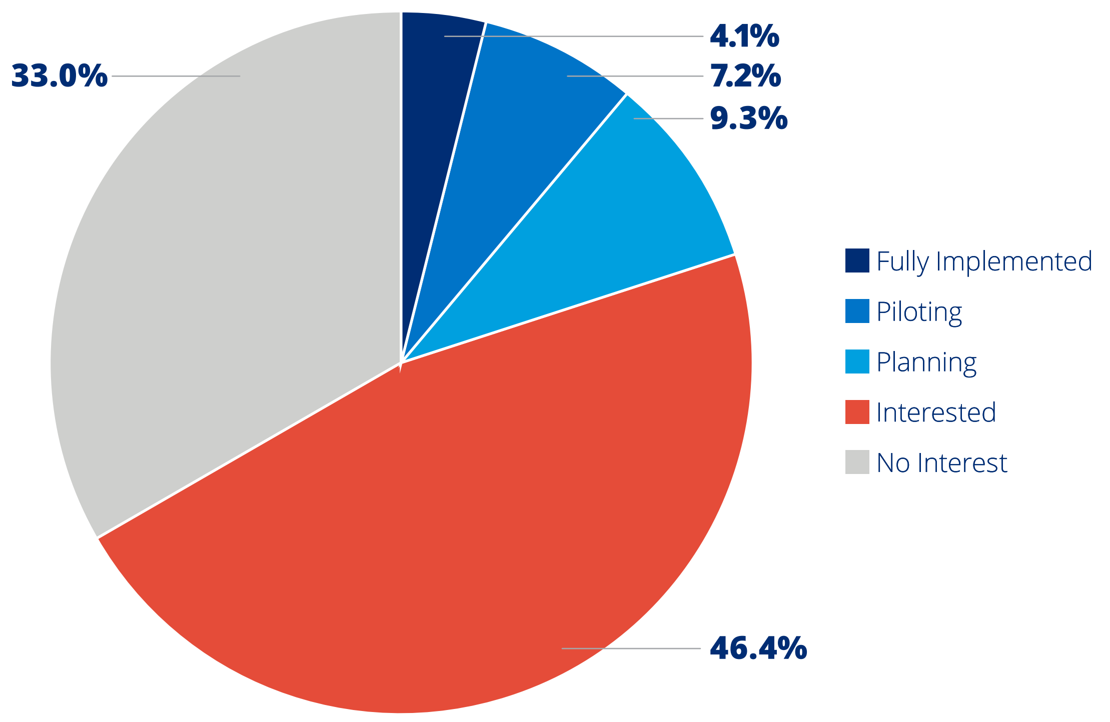
Industry Trends

Utilities are beginning to pair programs with different technology types to deliver holistic DR programs and provide additional grid services. SEPA Utility Survey results show interest in pairing DR with solar, storage and other technologies to provide more reliable demand reduction, with 68% of participating utilities interested, planning, piloting, or currently offering a DR pairing.

Energy storage, electric vehicles, and smart home devices all allow utilities the opportunity to use different DERs to help manage load, better account for increasing penetration of renewables, provide diverse solutions, and engage with customers. As the number of participants on the grid increases, and the nature of their interactions change, DR technologies will also see applicability in transactive energy systems.

The following section spotlights these advanced applications of DR, as already being explored in various utility pilots.

Figure 19: Advanced Applications of DR with Solar, Storage, and Energy Efficiency



Source: Smart Electric Power Alliance, 2019. N = 97 Utility Survey participants.

MW = Megawatts-ac

Energy Storage and Demand Management

As the energy storage market expands, it will play a growing role in demand management and renewable energy integration. Utilities are recognizing the value that aggregated energy storage can offer in DR efforts, by reducing renewable energy curtailment, leading to increased renewable energy penetration.

Energy Storage Program Highlights

In 2019, **Green Mountain Power (GMP)** started a Resilient Home pilot program—intending to shift away from meters by using Powerwall batteries to measure energy usage. Customers can enroll through GMP or a third party, and receive two batteries which provide clean backup power during outages and also measure energy usage. This makes homes more resilient while reducing carbon emissions. GMP calls on the network to reduce load during peak demand events, reducing costs for all customers. If the regional peak set this earlier summer holds, this network will offset about $800,000 in costs.

In February, 2019, **Southern California Edison**, in partnership with **Ice Energy**, completed the installation of 100 thermal storage cooling units at C&I sites, as the first phase of a project expected to grow to more than 1,200 systems over the next two years. By 2021, the project is expected to have a total storage capacity of 21.6 MW, 130 MWh. The systems, known as Ice Bears®, perform rate arbitrage, freezing ice during off-peak hours and then cooling in place of traditional air conditioners during peak demand to decrease C&I customers peak energy consumption.[20]

In 2018, **United Power** in Colorado interconnected two battery storage systems, totalling 4.5 MW, 18 MWh of energy storage. The two systems are called upon four to five times a month to shave peak demand and are then recharged from the grid during the night. United Power estimates that the battery storage systems will save the cooperative and its members $1 million annually from reduced generation charges during peak demand events.[21]

National Grid and **EnergyHub** are currently expanding the "ConnectedSolutions" program from a BYOT to a BYOD program, allowing customers to install and enroll their own battery storage devices. The program includes nine thermostat brands and five storage vendors. The expansion of this program shows that the BYO model is a successful way to engage with customers, and potentially yield a year-round resource. By developing a more robust and advanced system, customer incentives can expand and utilities can create a more sustainable business model. The expansion of this program to include battery energy storage allows behind-the-meter solar plus storage to export excess electricity to the grid.[22]

20 PV Magazine. (2019). Ice Energy brings the deep freeze to U.S. energy storage. Retrieved from https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/

21 Marizza, J. (2019, June 11). Phone Interview.

22 EnergyHub. (2018). National Grid selects EnergyHub as the platform provider to enhance its Bring Your Own Device demand response program. Retrieved from https://www.energyhub.com/blog/national-grid-bring-your-own-device-demand-response-program

MW = Megawatts-ac

Electric Vehicles as Grid Assets

By 2030, over 20 million electric vehicles (EVs) are expected to be on U.S. roads, representing 93 TWh of added electric load.[23] Without managed charging functionality, these vehicles could lead to grid constraints and unplanned costs. Managed charging will be a key part of utilities' DR portfolios, and implemented properly, can lower the cost of electricity grid payments for customers and provide benefits to the grid.

Table 7: Examples of Active and Passive Managed Charging

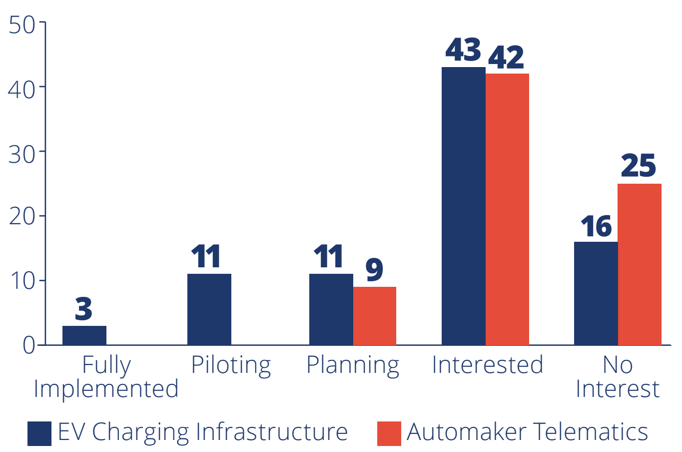
Passive	Active
EV time-varying rates, including time-of-use rates and hourly dynamic rates	Direct load control via the charging device
Communication to customer to voluntarily reduce charging load (e.g., behavioral DR event)	Direct load control via automaker telematics
Incentive programs rewarding off-peak charging	Direct load control via a smart circuit breaker or panel

Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019.

Utility Managed Charging Landscape

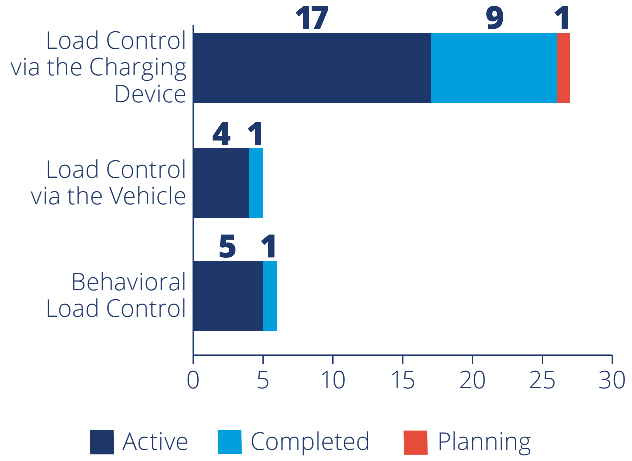
From SEPA's 2019 Utility Demand Response Survey of 84 respondents, 53% were interested in EV managed charging DR programs and only 26% expressed no interest (aggregated results from managed charging via charging infrastructure and automaker telematics). The survey revealed more utility interest in direct load control via the charging infrastructure than through automaker telematics.

Figure 20: Utility Interest in Managed Charging Programs by Technology Type



Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019. N=84

Figure 21: Utility-Run Managed Charging Projects by Type and Stage, United States, 2012-2019



Source: Smart Electric Power Alliance, A Comprehensive Guide to EV Managed Charging, 2019. N=38

23 Gartner J. (2018, February 19). Email Correspondence.

MW = Megawatts-ac

Electric Vehicle Program Highlights

Some utilities are using pilot programs in limited service areas to understand the effectiveness of managed charging. **Avista Utilities** was able to curtail loads during DR events and **PG&E** utilized automaker telematics and second-life batteries to ensure load-gaps were met.

Avista created a managed charging pilot in Washington state to test its ability to shift EV demand to off-peak hours. Avista collected data on the charging habits of customers and ran DR events. Customers could be notified a day before a DR event and then had the option to opt out. The pilot program was successful in shifting EV charging load to off-peak hours without disrupting customers. Avista was able to curtail load up to 75% with no customer complaints. If customers' cars were charged when needed then no issues arose with managed charging. Avista found that currently the costs of the program are higher than the savings, and it is difficult to estimate at what level of EV penetration these programs will make fiscal sense.

PG&E partnered with **BMW** in a managed charging pilot program that enrolled 96 model i3 drivers. BMW developed proprietary aggregation software, which could delay charging via cellular telematics. BMW also implemented second-life stationary batteries to meet load gaps in DR. BMW met 90% of the load requirements for DR events with an average 20% contribution from EVs and 80% from the battery system. Limited availability of EVs for DR events highlighted a potential concern. This program also used a TOU rate for EV charging. In a second phase, the program was expanded to 350 participants and supported the use of EV managed charging to optimize for load conditions. Managed charging was able to shift EV charging to times when it was cheapest and cleanest.

PG&E expects more than 1.5 million EVs in its region by 2030.[24] From Phase 1 results, the potential load drop of a single event in 2030 could be as much as 77.6 MW, enough to power 58,000 California homes.[25]

24 Pacific Gas and Electric Company And BMW Group (2017). BMW I ChargeForward PG&E's Electric Vehicle Smart Charging Pilot. Retrieved from https://efiling.energy.ca.gov/GetDocument.aspx?tn=221489

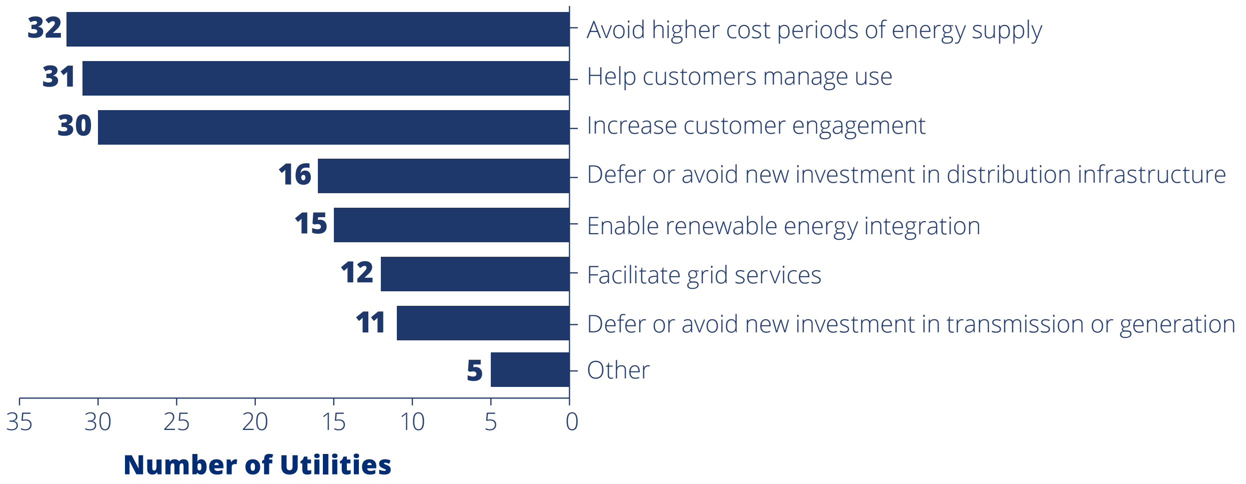
25 Smart Electric Power Alliance (SEPA). (2019). A Comprehensive Guide to EV Managed Charging. Retrieved from https://sepapower.org/resource/a-comprehensive-guide-to-electric-vehicle-managed-charging/

MW = Megawatts-ac

The 2019 Utility Demand Response Survey also asked how utilities planned to use or were using managed charging. Utilities indicated the most common use for managed charging was to avoid periods of higher cost energy (22%). Utilities' next most common use was to help customers manage their energy use (21%). Third, was using managed charging to increase customer engagement (20%). The potential uses for managed charging are not mutually exclusive and better developed managed charging systems should capture savings and customer engagement in energy management.

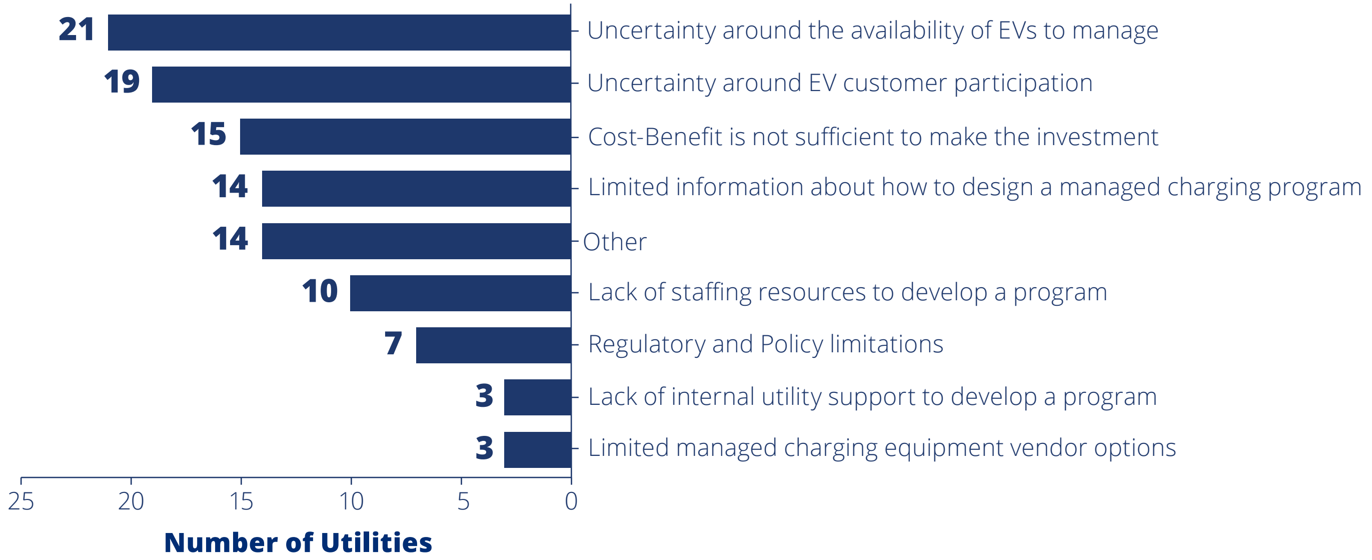
The survey asked these same utilities what barriers existed to implementing managed charging programs. Top concerns were the availability of EVs to manage via these programs (20%), uncertainty about customer participation in managed charging programs (18%), concern that the cost-benefit ratio would be insufficient to justify investment (14%), and limited information about implementation and design of managed charging programs (13%). Some utilities were unsure how to prioritize managed charging with other DR programs, or did not have sufficient EV penetration to justify investments, making up "other" barriers.

Figure 22: How Utilities are Using or Planning to Use Managed Charging



Source: Smart Electric Power Alliance, 2019. N=48. Note: Utilities selected all that applied.

Figure 23: Barriers to Implementing a Managed Charging Program



Source: Smart Electric Power Alliance, 2019. N=45. Note: Utilities selected all that applied.

MW = Megawatts-ac

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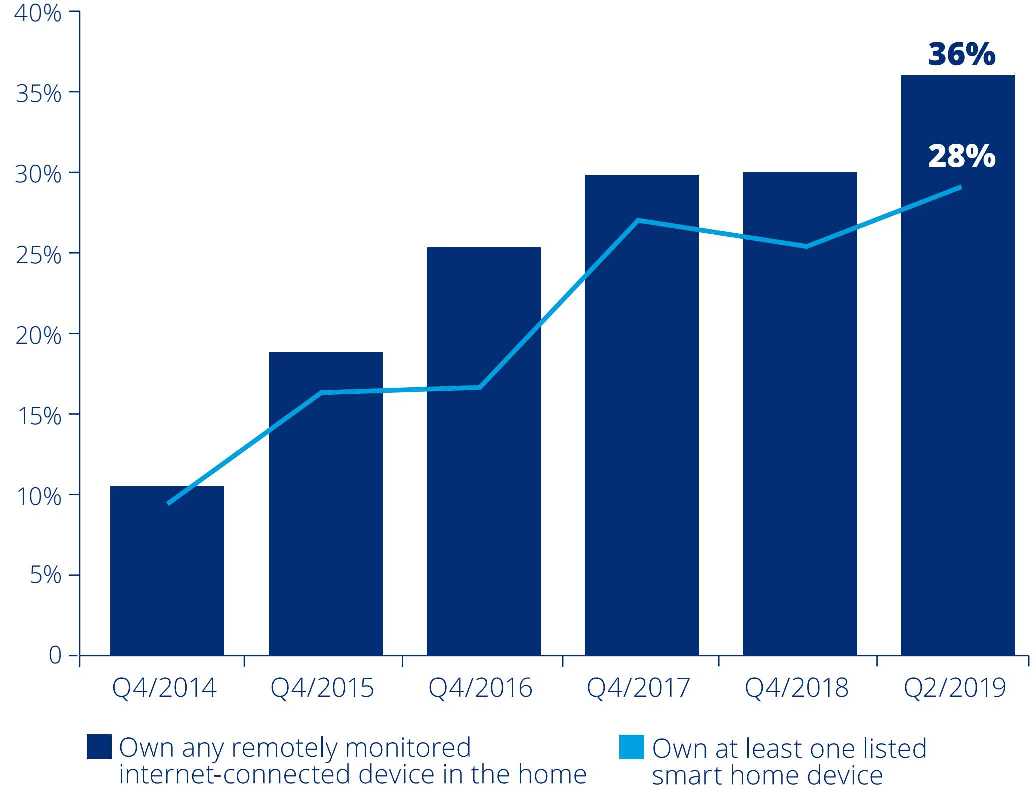
Demand Flexibility: Opportunities in the Smart Home

Opportunities continue to expand at the residential level as technology opens up new business models for utilities and third parties in the industry. Smart energy device ownership in U.S. broadband households has trended upwards over the last 4 years, with Parks Associates estimating nearly 36% of households own remotely monitored internet-connected smart home devices in their home. Smart energy devices remain the most popular, with smart thermostats ranking #1 and smart light bulbs ranking #3 in ownership of smart home devices.

Additionally, opportunities are continuing to expand with growing partnerships between third parties and utilities. Google recently announced a program allowing utility companies to integrate with the tech giant's platform, allowing greater integration to take advantage of Google's voice platform and capabilities while providing consumers with a more personalized and interactive experience with their utility provider.

Figure 24: Smart Home Device Ownership: Among All U.S. Broadband Households



Smart Home Devices Surveyed (Q2 2019)*

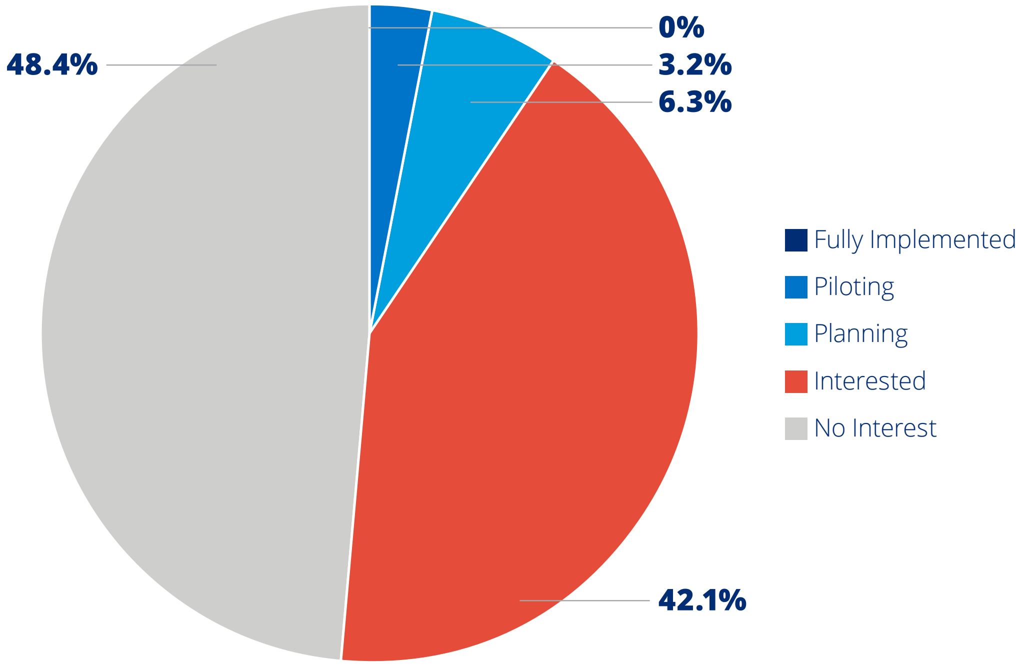
- Thermostats
- Door Locks
- Video Door Bells
- IP Cameras
- Light Bulbs
- Lighting Control Systems
- Outdoor Light Fixtures with Video Cameras
- Outlets/Switches/Dimmers
- Smart Plugs/Adapters
- Sprinkler Systems
- Garage Door Openers
- Smoke/CO Detectors
- Water Leak Detectors
- Water Shut-off Valve
- Smart Appliance

*This list of devices has changed slightly over the years to include new products.

MW = Megawatts-ac

Wood Mackenzie Power & Renewables estimates 48 million U.S. households will be using voice-assistants as the central interface for smart home functions in the years to come.[26] With a growing number of consumers adopting smart home devices at the grid edge (e.g., Google Home, Amazon Alexa devices), utilities and solution providers have opportunities to further integrate and automate energy management at the home level.

Figure 25: Integrating Voice-enabled Smart Home Devices Into Any New or Existing DR Programs



Source: Smart Electric Power Alliance, 2019. N=95 Utility Survey participants.

Utilities are starting to leverage new smart home assistants and device integration to increase customer engagement with their energy use. A handful of utilities are exploring demand flexibility at the smart home level. The SEPA Utility Survey found that 3.1% of utilities piloted the integration of voice-enabled smart home devices into their DR programs, 6.2% are planning programs, and over 40% are interested. These responses demonstrate that utilities are interested in pursuing a more integrated approach to home energy management and customer education.

Voice Control & Activation

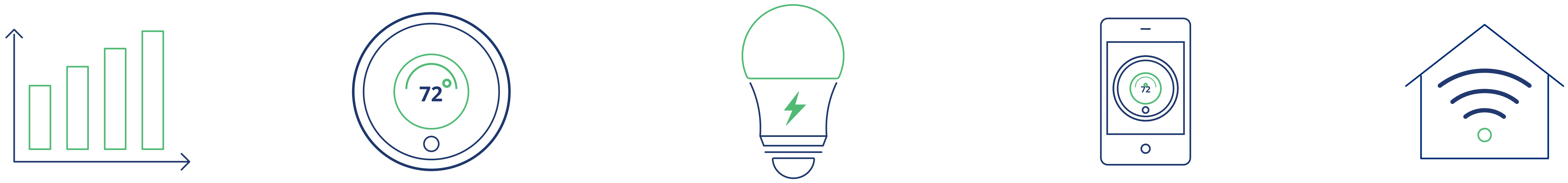
Uplight (formerly known as Tendril), working with **Indiana Michigan Power**, developed voice assistant applications for Google Assistant and Amazon Alexa that enable consumers to learn about and manage their energy usage through voice interactivity. The program can use integrated display functionality for screen-enabled voice assistants--including Amazon's Echo Show and Google's Nest Hub--to display relevant energy usage visuals and other supplemental content. The program provides a foundation for expanding functionality for optimized home energy management and automated control of Smart Home devices such as lighting and appliances. It currently allows users to inquire about their energy usage, real-time bill amount and payment status, and provides personal suggestions to improve energy efficiency. Uplight provides unique insights using data insights from more than 123 million homes. The key goal of the program is to improve customer engagement and inform them about their usage to promote behavioral energy efficiency.

26 Wood Mackenzie. (2018). Energy Management in the Connected Home: Competitive Landscape, Forecasts and Case Studies. Retrieved from https://www.woodmac.com/reports/power-markets-energy-management-in-the-connected-home-competitive-landscape-forecasts-and-case-studies-58129606

MW = Megawatts-ac

Opportunities in home energy management can be represented as 5 levels, as laid out in a Powerly framework (see Figure 26)—initial data visualization (level 0), real-time energy monitoring (level 1), smart connected devices (level 2), providing personalized insights to customers based on their energy use (level 3), and full home optimization (level 4). Today, utilities are mostly at the initial stage of historical data visualization, although SEPA Utility Survey results show movement into levels 2 and 3, with interest in full home optimization (level 4).

Figure 26: Four Levels of Autonomous Home Energy Management



Level 0

Hitorical Data Visualization

Access to historical energy data, typically through online portals or Home Energy Reports.

Level 1

Real-Time Energy Monitoring

A real-time connection to a home's energy use.

Level 2

Real-time w/Connected Devices

Connectivity to smart devices, allowing for control and management of appliances

Level 3

Insight Assisted Change

Provide personalized insights of home and appliance health.

Level 4

Full Home Optimization

A personalized and autonomous optimization engine for the home that balances comfort and efficiency.

Source: Powerly, 2019

MW = Megawatts-ac

Transactive Energy

DR has the potential to play a large role in meeting the needs and challenges of an evolving grid. With increasing distributed renewable energy resources and more grid participants, the grid is becoming more decentralized, variable, and complex. Additionally, consumers are generating power, interacting and transacting with each other or their utilities, and actively managing their energy consumption.

In this increasingly complex environment, DR has the potential to serve the important role of ensuring that load supply and demand are matched. Transactive energy is one potential system that can leverage DR in order to create and sustain a complex system of consumers, producers, and prosumers, while enabling distributed control and balancing.[27]

Transactive energy is a system comprised of coordinated participants (i.e., devices and equipment) that use automation tools to communicate and exchange energy based on value and grid reliability constraints.[28] Participants buy and sell energy and ancillary services, and negotiate between themselves through market mechanisms. Many of the existing transactive energy pilots incorporate DR technology, and are an expansion of DR principles. Transactive energy systems can automate DR by using devices that are able to read utility signals while also allowing a diversity of smart home technologies and customer preferences. Grid needs, value and price, and customer preferences are incorporated to enable transactions between participants. The following cases demonstrate this integration of DR into transactive energy systems.

27 CGI. (2019). Optimized Network Utilities and Demand Response. Retrieved from https://www.cgi.com/sites/default/files/white-papers/cgi-onu-demand-response-wp.pdf
28 SEPA. (2019). Transactive Energy: Real-World Applications for the Modern Grid. Retrieved from https://sepapower.org/resource/transactive-energy-real-world-applications-for-the-grid/

MW = Megawatts-ac

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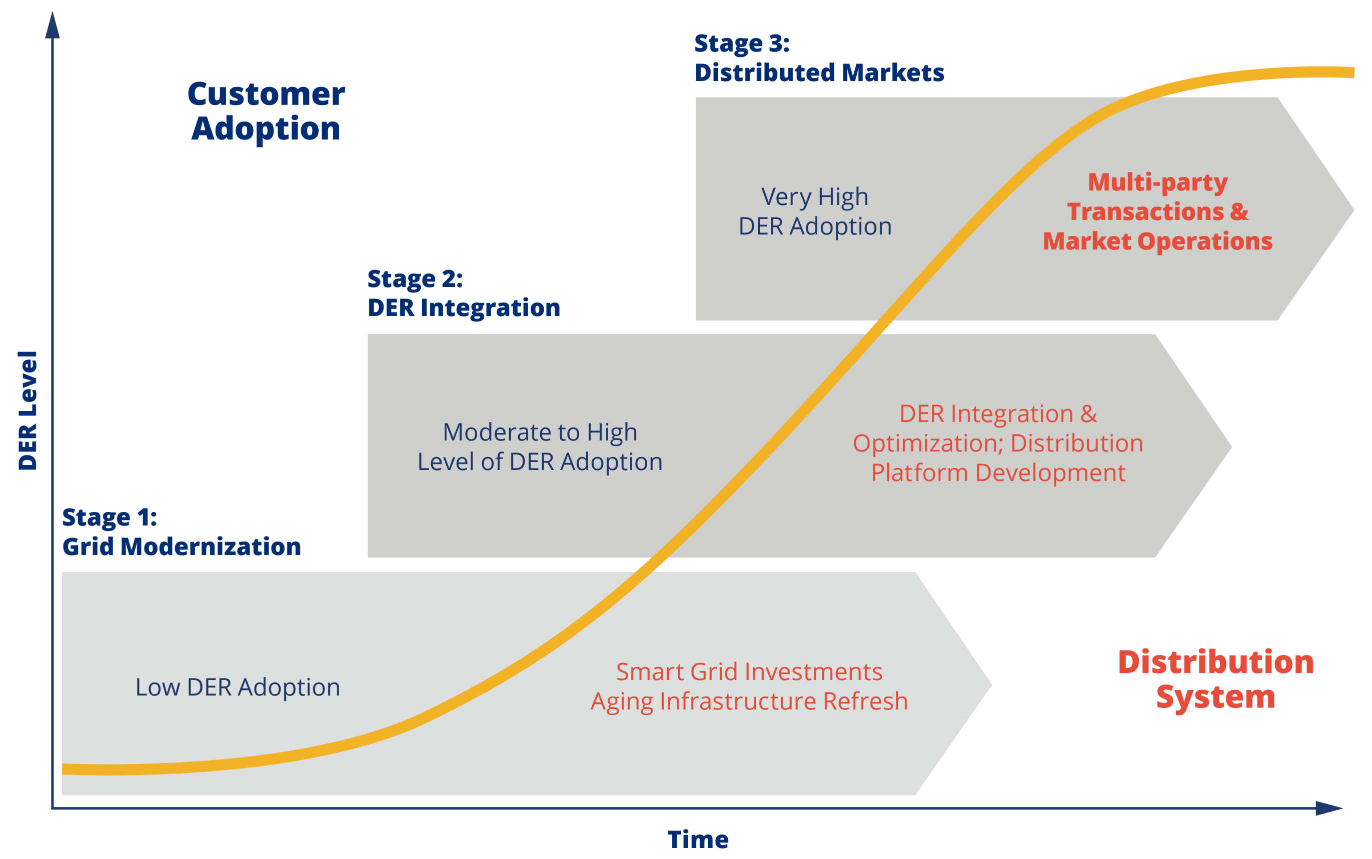
Figure 27: Evolution of the Distribution System with Increasing Levels of DERs



Source: Paul De Martini and Lorenzo Kristov, 2015

Figure 27 illustrates a three-stage evolutionary framework for a distribution system with increasing levels of DERs. Each level expands on the capabilities of the earlier stage, and includes additional functionalities needed to support greater amounts of DER adoption. Most distribution systems in the U.S. are currently at Stage 1.

Stage 1 is characterized by: grid modernization and reliability investments that are underway or planned for the near term; low customer adoption of DER; and limited or non-existent DER participation in wholesale markets.

In **Stage 2**, DER adoption reaches higher levels, requiring enhanced functional capabilities to maintain reliable distribution system operation. Two-way power flows will be needed on high-DER circuits, requiring more advanced protection and control technologies and operational capabilities to ensure safety and reliability. Additionally, the increased level of DERs may provide an opportunity to deliver services to the bulk power system.

In **Stage 3**, DER providers and consumers go beyond providing traditional services, and seek to engage in energy transactions, requiring regulatory and operational changes to enable such transactions. These transactions will require more coordination between retailers, distribution system operators (DSOs), and transmission system operators at the point where transmission and distribution systems interconnect.

MW = Megawatts-ac

Transactive Energy Program Highlights

National Grid and **Opus One Solutions** launched a pilot program on the Buffalo Niagara Medical Campus (BNMC) to create a distribution-level transactive energy marketplace for DER owners and operators. The pilot tested the communications between a DSP and network-connected DERs using DR, combined heat and power, and existing backup generators. Energy storage and renewable generation are also being evaluated for possible inclusion. This pilot program was designed to evaluate a financial model for DER market participation based on the value of DER, using the New York Independent System Operator's (NYISO) locational marginal price plus the value of DER to the distribution grid. The project demonstrated that there is customer interest.

Pacific Northwest National Laboratory launched the The Olympic Peninsula pilot in Washington state and used two-way exchange of load price/quantity curves and electric market-cleared price signals to coordinate four municipal water pumps, two backup diesel generators, and residential DR from electric water and space heating systems in 112 homes. The project demonstrated the ability of transactive energy to manage system peak load and distribution constraints; enable utility wholesale price purchases; enable generators, loads, and appliances to automatically bid or offer into a real-time energy market; and provide cost savings for customers and the municipality.

Southern California Edison (SCE), **TeMix Inc.** and **Universal Devices**, introduced a pilot in 2015 that uses smart home devices to coordinate and automate customer device management and transactions with SCE distribution operators, energy service providers, and the California ISO.

Device operations are automated through cloud-hosted energy management systems that use machine learning, customer preference, optimization, and sensor input to automatically respond to current and forward tender prices. Customer input is simplified with the use of Amazon Alexa voice responses. The pilot includes a retail two-way subscription tariff which allows customers to subscribe to fixed amounts of electricity, shaped to match their typical hourly kWh quantity. The pilot was deployed successfully, with two-way price signals occurring between CAISO and SCE, and SCE and its customers.

SCE is using the lessons learned from the pilot to implement smart home platforms. These efforts target energy efficiency and universal devices, where automated assistants are increasing customer interaction and helping people communicate with the system for improved comfort and energy savings. SCE is also engaged in a pilot that shifts load by sharing information about time of use rates via a smart speaker.

MW = Megawatts-ac

Appendix A: Survey Participants

A&N Electric Cooperative
AEP Texas
Aiken Electric Cooperative, Inc.
Alliant Energy
Ameren Illinois
American Samoa Power Authority
Anaheim Public Utilities
Appalachian Power Company - Tennessee
Appalachian Power Company - West Virginia
Arizona Public Service
Atlantic City Electric Company
Austin Energy
Austin Utilities - Minnesota
Avista Utilities - Idaho
Avista Utilities - Washington
Baltimore Gas & Electric
Belmont Light
Berkeley Electric Cooperative, Inc.
Big Bend Electric Cooperative, Inc.
Black River Electric Cooperative, Inc.
Blue Ridge Electric Cooperative
Blue Ridge Electric Membership Corporation
Bonneville Power Authority - California
Bonneville Power Authority - Idaho
Bonneville Power Authority - Montana
Bonneville Power Authority - Nevada
Bonneville Power Authority - Oregon
Bonneville Power Authority - Utah
Bonneville Power Authority - Washington
Bonneville Power Authority - Wyoming
Braintree Electric Light Department
Broad River Electric Cooperative, Inc.
City of Fort Collins
City of Holyoke
City of Palo Alto Utilities
City of Tallahassee
City Utilities of Springfield, Missouri
Coastal Electric Cooperative, Inc.
Cobb Electric Membership Corporation
Commonwealth Edison Company
Consolidated Edison Company of New York, Inc.
Consumers Energy
CoServ Electric
CPS Energy
Cumberland Valley Electric
Dairyland Power Cooperative
Delaware Electric Cooperative
Delmarva Power - Delaware
Delmarva Power - Maryland
Detroit Edison
Dominion Energy North Carolina
Dominion Energy Virginia
Duke Energy (FL)
Duke Energy Carolinas, LLC - North Carolina
Duke Energy Carolinas, LLC - South Carolina
Duke Energy Indiana
Duke Energy Ohio Inc. - Kentucky
Duke Energy Ohio Inc. - Ohio
Duke Energy Progress - North Carolina
Duke Energy Progress - South Carolina
Edisto Electric Cooperative, Inc.
El Paso Electric
Entergy Arkansas
Entergy Louisiana
Entergy Mississippi
Entergy New Orleans
Entergy Texas
Eversource
Fairfield Electric Cooperative, Inc.
Farmers Electric Cooperative, Inc.
Fitchburg Gas and Electric Light Company
Flint Energies
Florida Power & Light Company
Georgia Power Company

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Glendale Water & Power
Great River Energy
Guadalupe Valley Electric Cooperative, Inc.
Gulf Power Company
Hancock-Wood Electric Cooperative, Inc.
Hawaii Electric Light Company
Hawaiian Electric Company
Heber Light & Power
Hoosier Energy Rural Electric Cooperative, Inc.
Horry Electric Cooperative
Idaho Power Company
Indiana Michigan Power
Indianapolis Power & Light Company (AES)
Jersey Central Power & Light
Kansas City Power & Light
Lakeland Electric
Laurens Electric Cooperative
Lincoln Electric System
Little River Electric Cooperative
Los Angeles Dept of Water and Power
Lynches River Elec Cooperative, Inc.
Madison Gas & Electric Company
Marlboro Electric Cooperative, Inc.
Massachusetts Electric Company
Medina Electric Cooperative, Inc.
Memphis Light, Gas and Water Division
Metropolitan Edison Company
Mid-Carolina Electric Cooperative Inc.
Middleborough Gas and Electric Department
Modesto Irrigation District
Monongahela Power Company
Nebraska Public Power District
New Braunfels Utilities
New Hampshire Electric Cooperative, Inc.
Newberry Electric Cooperative
Niagara Mohawk Power Corporation
Northern Neck Electric Cooperative, Inc.
Northern States Power Minnesota (Xcel) - Colorado
Northern States Power Minnesota (Xcel) - Minnesota
Northern States Power Minnesota (Xcel) - North Dakota
Northern States Power Minnesota (Xcel) - South Dakota
Northern States Power Texas (Xcel) - New Mexico
Northern States Power Texas (Xcel) - Texas
Northern States Power Wisconsin (Xcel) - Michigan
Northern States Power Wisconsin (Xcel) - Wisconsin
Northwest Rural Public Power District
NV Energy
Ohio Edison Company
Oklahoma Gas & Electric
Omaha Public Power District
Orange and Rockland Utilities, Inc.
Otter Tail Power Company - Minnesota
Otter Tail Power Company - North Dakota
Otter Tail Power Company - South Dakota
Pacific Gas & Electric
PacifiCorp - Idaho
PacifiCorp - Oregon
PacifiCorp - Utah
Palmetto Electric Cooperative
PECO Energy Company
Pedernales Electric Cooperative, Inc.
Pee Dee Electric Cooperative, Inc.
Penn Power Company
Pennsylvania Electric Company
Portland General Electric
Potomac Edison Company
Potomac Edison Company
Potomac Edison Company - Virginia
Potomac Electric Power Company - DC
Potomac Electric Power Company - Maryland
PowerSouth Energy Cooperative
PPL Electric Utilities Company
Public Service Company of Oklahoma
Public Service Electric & Gas
Randolph Electric Membership Corporation
Rappahannock Electric Cooperative
Riverside Public Utilities

MW = Megawatts-ac

Roseville Electric

Sacramento Municipal Utility District

San Diego Gas & Electric

Santee Electric Cooperative

Seattle City Light

Southern California Edison

Southern Maryland Electric Cooperative, Inc.

Southwestern Electric Power Company - Arkansas

Southwestern Electric Power Company - Texas

Sterling Municipal Light Department

Tampa Electric Company

Tennessee Valley Authority - Alabama

Tennessee Valley Authority - Georgia

Tennessee Valley Authority - Kentucky

Tennessee Valley Authority - Mississippi

Tennessee Valley Authority - North Carolina

Tennessee Valley Authority - Tennessee

Tennessee Valley Authority - Virginia

The Illuminating Company

The Narragansett Electric Company

Toledo Edison Company

Town of Littleton

Town of Middleton

Tri-County Electric Cooperative

Trico Electric Cooperative, Inc.

Turlock Irrigation District

United Power, Inc.

Unitil Energy Systems

Vectren Corporation

Vermont Electric Cooperative

Village of Bergen

Village of Sherburne

Vineland Municipal Utilities

We Energies

West Penn Power Company

Westar Energy

Wisconsin Public Service

WPPI Energy

York Electric Cooperative, Inc.

Appendix B: 2018 Reported Demand Response Capacity State and Select Territories (MW)

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Alabama	468.0	329.0
Alaska	-	-
American Samoa	0	0
Arizona	40.0	26.9
Arkansas	181.7	199.2
California	1,335.4	1,002.8
Colorado	499.6	265.4
Connecticut	-	-
Delaware	136.2	130.2
District of Columbia	23.0	21.0
Florida	2,911.4	611.4
Georgia	973.1	50.9
Guam	-	-

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Hawaii	34.9	34.9
Idaho	628.5	527.0
Illinois	1,146.5	196.6
Indiana	842.3	790.2
Iowa	440.0	440.0
Kansas	291.7	44.7
Kentucky	170.8	150.8
Louisiana	0.4	0.4
Maine	-	-
Marshall Islands	-	-
Maryland	1,212.8	1,200.5
Massachusetts	75.3	72.3
Michigan	651.4	112.6

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Minnesota	805.6	423.6
Mississippi	392.0	64.0
Missouri	170.0	164.0
Montana	0.0	0.0
Nebraska	82.6	64.9
Nevada	207.2	190.1
New Hampshire	6.5	4.5
New Jersey	121.0	55.0
New Mexico	7.7	3.7
New York	981.1	903.9
North Carolina	1,319.8	968.4
North Dakota	109.0	42.6
Ohio	745.9	678.2
Oklahoma	172.4	75.4
Oregon	84.0	16.4
Pennsylvania	606.4	552.1

Table 8: Total Demand Response Enrolled and Dispatched Capacity by State and Select Territory

Operating State/ Territory	Sum of Total Enrolled Capacity	Sum of Total Dispatched Capacity
Puerto Rico	-	-
Rhode Island	19.4	19.4
South Carolina	398.6	310.6
South Dakota	49.0	16.9
Tennessee	631.0	476.8
Texas	574.8	490.9
Utah	249.0	211.0
Vermont	0.1	0.0
Virgin Islands	-	-
Virginia	259.7	75.5
Washington	0	0
West Virginia	129.2	129.2
Wisconsin	590.6	160.3
Wyoming	0	0
Total	20,775.4	12,304.1

Source: Smart Electric Power Alliance, 2019.

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