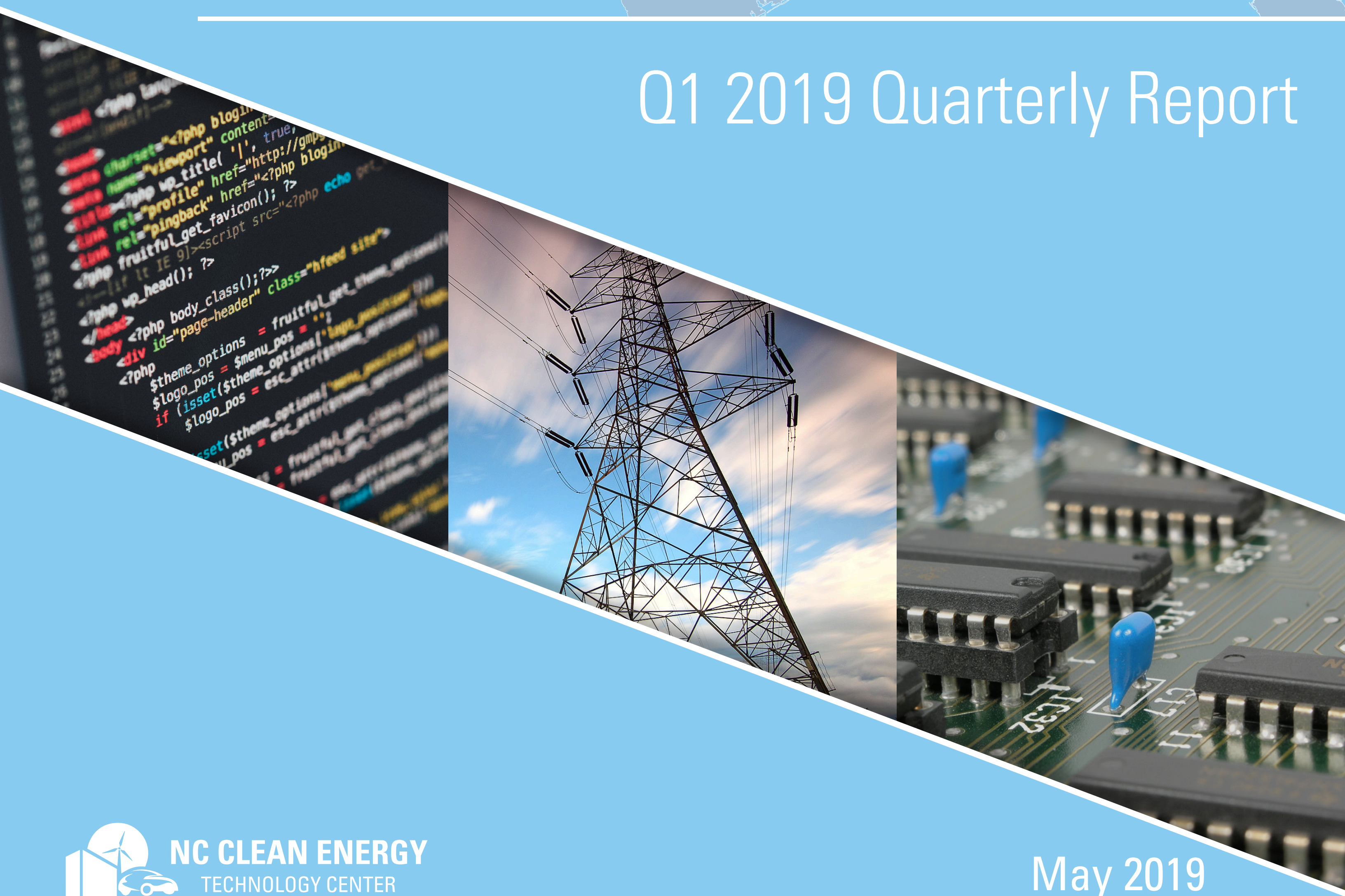
50 States of GRID MODERNIZATION

Q1 2019 Quarterly Report



NC CLEAN ENERGY TECHNOLOGY CENTER

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

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PREVIOUS EDITIONS AND OTHER 50 STATES REPORTS

The 50 States of Grid Modernization is a quarterly publication. Previous executive summaries and older full editions of *The 50 States of Grid Modernization* are available here.

In addition to *The 50 States of Grid Modernization*, the NC Clean Energy Technology Center publishes additional quarterly reports called *The 50 States of Solar* and *The 50 States of Electric Vehicles*. These reports may be purchased at here. Executive summaries and older editions of these reports are available for download here.

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GLOSSARY OF ABBREVIATIONS

ALJ	Administrative Law Judge
d/b/a	Doing Business As
DER	Distributed Energy Resource
DG	Distributed Generation
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
GW	Gigawatt
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
MW	Megawatt
NEM	Net Energy Metering
PACE	Property Assessed Clean Energy
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit (or Certificate)
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
TOU	Time-of-Use

OVERVIEW

WHAT IS GRID MODERNIZATION?

Grid modernization is a broad term, lacking a universally accepted definition. In this report, the authors use the term grid modernization broadly to refer to actions making the electricity system more resilient, responsive, and interactive. Specifically, in this report grid modernization includes legislative and regulatory actions addressing: (1) smart grid and advanced metering infrastructure, (2) utility business model reform, (3) regulatory reform, (4) utility rate reform, (5) energy storage, (6) microgrids, and (7) demand response.

PURPOSE

The purpose of this report is to provide state lawmakers and regulators, electric utilities, the advanced energy industry, and other energy stakeholders with timely, accurate, and unbiased updates about how states are choosing to study, adopt, implement, amend, or discontinue policies associated with grid modernization. This report catalogues proposed and enacted legislative, regulatory, and rate design changes affecting grid modernization during the most recent quarter.

The 50 States of Grid Modernization report series provides regular quarterly updates and annual summaries of grid modernization policy developments, keeping stakeholders informed and up to date.

APPROACH

The authors identified relevant policy changes and deployment proposals through state utility commission docket searches, legislative bill searches, popular press, and direct communications with industry stakeholders and regulators.

Questions Addressed

This report addresses several questions about the changing U.S. electric grid:

- How are states adjusting traditional utility planning processes to better allow for consideration of advanced grid technologies?
- What changes are being made to state regulations and wholesale market rules to allow market access for distributed energy resources?
- How are states and utilities reforming the traditional utility business model and rate designs?

- What policy actions are states taking to grow markets for energy storage and other advanced grid technologies?
- Where and how are states and utilities proposing and deploying advanced grid technologies, energy storage, microgrids, and demand response programs?

Actions Included

This report focuses on cataloguing and describing important proposed and adopted policy changes related to grid modernization and distributed energy resources, *excluding policies specifically intended to support only solar technologies*. While some areas of overlap exist, actions related to distributed solar policy and rate design are tracked separately in the *50 States of Solar report series,* and are generally not included in this report.

In general, this report considers an "action" to be a relevant (1) legislative bill that has been introduced or (2) a regulatory docket, utility rate case, or rulemaking proceeding. Only statewide actions and those related to investor-owned utilities are included in this report. Specifically, actions tracked in this issue include:

Studies and Investigations

Legislative or regulatory-led efforts to study energy storage, grid modernization, utility business model reform, or alternative rate designs, e.g., through a regulatory docket or a cost-benefit analysis.

Planning and Market Access

Changes to utility planning processes, including integrated resource planning, distribution system planning, and evaluation of non-wires alternatives, as well as changes to state and wholesale market regulations enabling market access.

Utility Business Model and Rate Reform

Proposed or adopted changes to utility regulation and rate design, including performance-based ratemaking, decoupling, time-varying rates, and residential demand charges.

Grid Modernization Policies

New state policy proposals or changes to existing policies related to grid modernization, including energy storage targets, energy storage compensation rules, interconnection standards, and customer data access policies.

Financial Incentives for Energy Storage and Advanced Grid Technologies

New statewide incentives or changes to existing incentives for energy storage, microgrids, and other modern grid technologies.

Deployment of Advanced Grid Technologies

Utility-initiated requests, as well as proposed legislation, to implement demand response programs or to deploy advanced metering infrastructure, smart grid technologies, microgrids, or energy storage.

Actions Excluded

This report excludes utility proposals for grid investments that do not include any specific grid modernization component, as outlined above, as well as specific projects that have already received legislative or regulatory approval. Actions related exclusively to pumped hydroelectric storage or electric vehicles are not covered by this report (a separate report series available from the NC Clean Energy Technology Center covers electric vehicle actions). Time-varying and residential demand charge proposals are only documented if they are being implemented statewide, the default option for all residential customers of an investor-owned utility, or a notable pilot program. Actions related to inclining or declining block rates are not included in this report. While actions taken by municipal utilities and electric cooperatives are not comprehensively tracked in this report, particularly noteworthy or high-impact actions are included. The report also excludes changes to policies and rate design for distributed generation customers; these changes are covered in the 50 States of Solar quarterly report.

THE U.S. ELECTRICITY SYSTEM IN TRANSITION

The U.S. electricity grid is currently in a state of transition. The system was historically a "one-way street", with power flowing from utility-owned centralized generation, via utility-owned transmission and distribution lines, toward end-use consumers. However, the electric system is increasingly becoming more of an interconnected web, with small but growing numbers of end-use customers also generating at least some of their own electricity with small-scale, distributed systems that are often capable of providing various services to the grid.

Technology is making rapid advancements, offering new benefits to the electric system. Policy, however, has not kept pace with the speed of technical energy advancements, with most U.S. electricity policy still focused primarily on the traditional one-way, centralized system model and its industry structure and related institutions. This is changing, though, with more and more states initiating investigations into advanced grid technologies and proposing legislative and regulatory changes intended to enable the development of a modern electric system.

Grid Modernization

Grid modernization is an expansive topic, capturing the many individual pieces of the transition occurring in our nation's energy system. A major element of this transition is the deployment of new technologies, such as advanced metering infrastructure and smart grid technologies, including communications, monitoring, and control technologies for managing distributed energy resources of all kinds. These technologies offer the opportunity to bring new benefits to both utilities and consumers, including economic, environmental, reliability, security, and consumer experience benefits.

The deployment of advanced grid technologies is already underway. The market for distributed generation, namely solar photovoltaics, is already scaling rapidly, while the energy storage market is expected to grow from an expected 6 GW of annual installed capacity in 2017 to over 40 GW in 2022.[1] Utilities had already deployed nearly 76 million smart meters by the end of 2017, covering over 55% of U.S. households, and more installations are underway.[2]

But before advanced grid technologies can be utilized to their fullest extent, regulatory structures must be examined to determine whether current regulations are resulting in outdated or unintended barriers to deployment. By reevaluating regulatory frameworks, business models, and rate designs, an energy system that allows for full and open evaluation of technological options, greater market participation, and fair assignment of related benefits and costs can be created.

Over half of U.S. states are currently examining these regulatory frameworks or actively working to deploy advanced grid technologies. This activity is expected to continue, as states and utilities conduct studies, try new approaches, and learn from one other about how best to achieve the many benefits of a more modern grid.

OVERVIEW OF Q1 2019 GRID MODERNIZATION ACTION

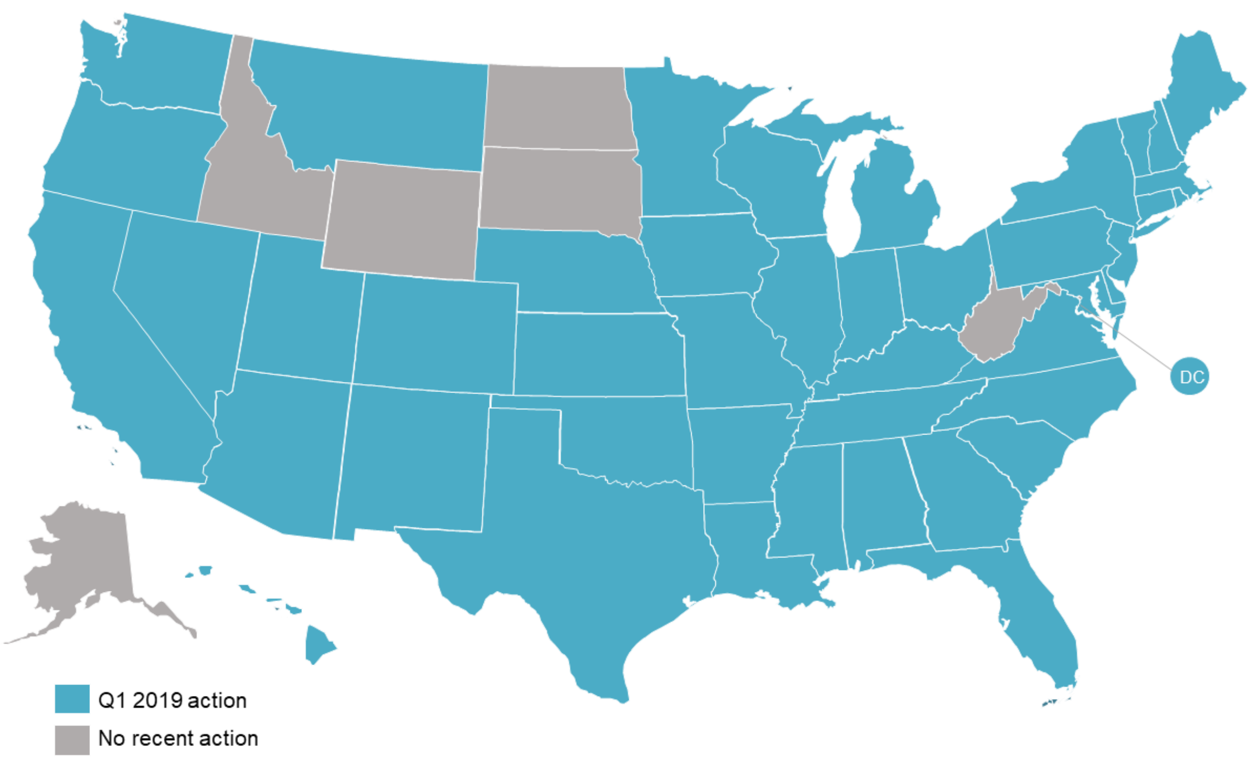
Table 1 provides a summary of state actions related to grid modernization occurring during Q1 2019. Of the 395 actions catalogued, the most common were those related to policies (104), planning and market access (68), and deployment (62). The actions occurred across 44 states plus DC in Q1 2019 (Figure 1). Box 1 highlights the states that saw the most grid modernization action during Q1 2019, described in greater detail in the following sections.

Table 1. Q1 2019 Summary of Grid Modernization Actions

Type of Action	# of Actions	% by Type	# of States
Policies	104	26%	31
Planning and Market Access	68	17%	26 + DC
Deployment	62	16%	27
Studies and Investigations	60	15%	26 + DC
Business Model and Rate Reform	57	14%	28
Financial Incentives	44	11%	18
Total	**395**	**100%**	**44 States + DC**

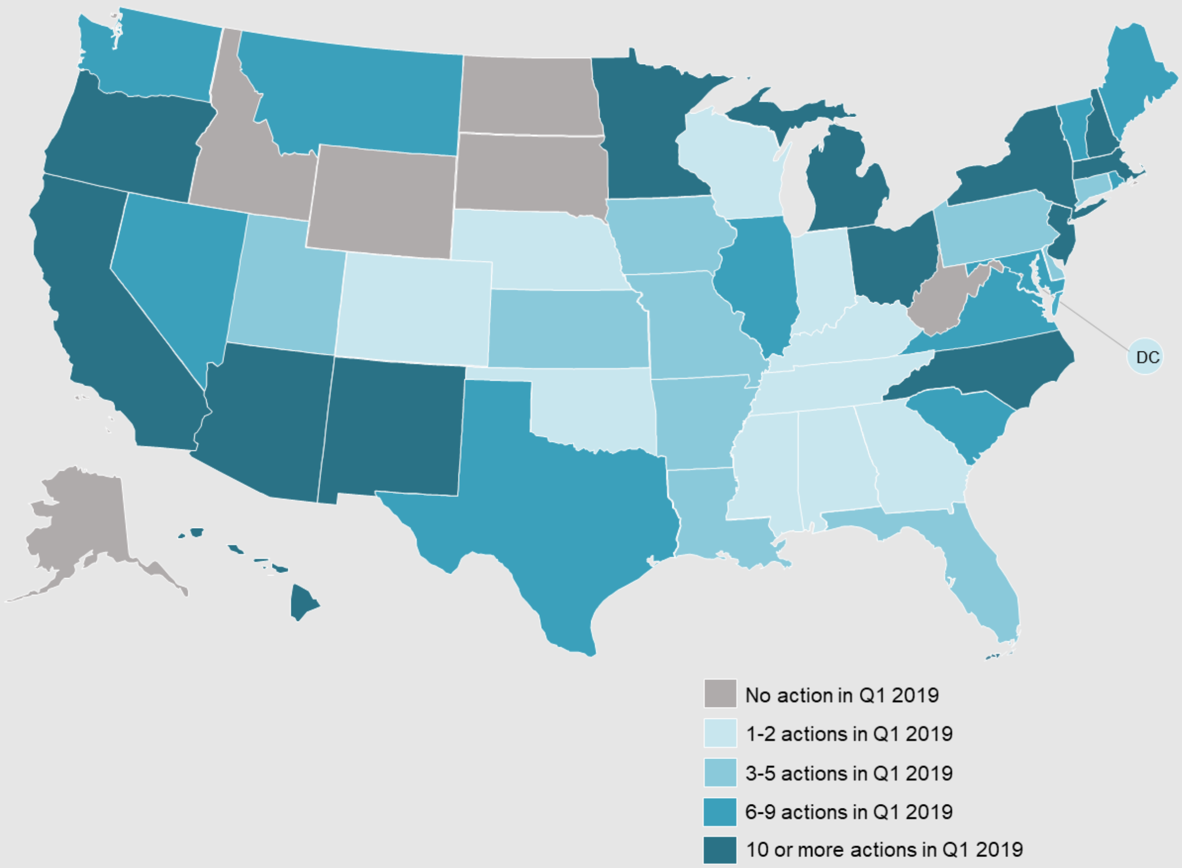
Note: The "# of States/ Districts" total is not the sum of the rows because some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 1. Q1 2019 Legislative and Regulatory Action on Grid Modernization



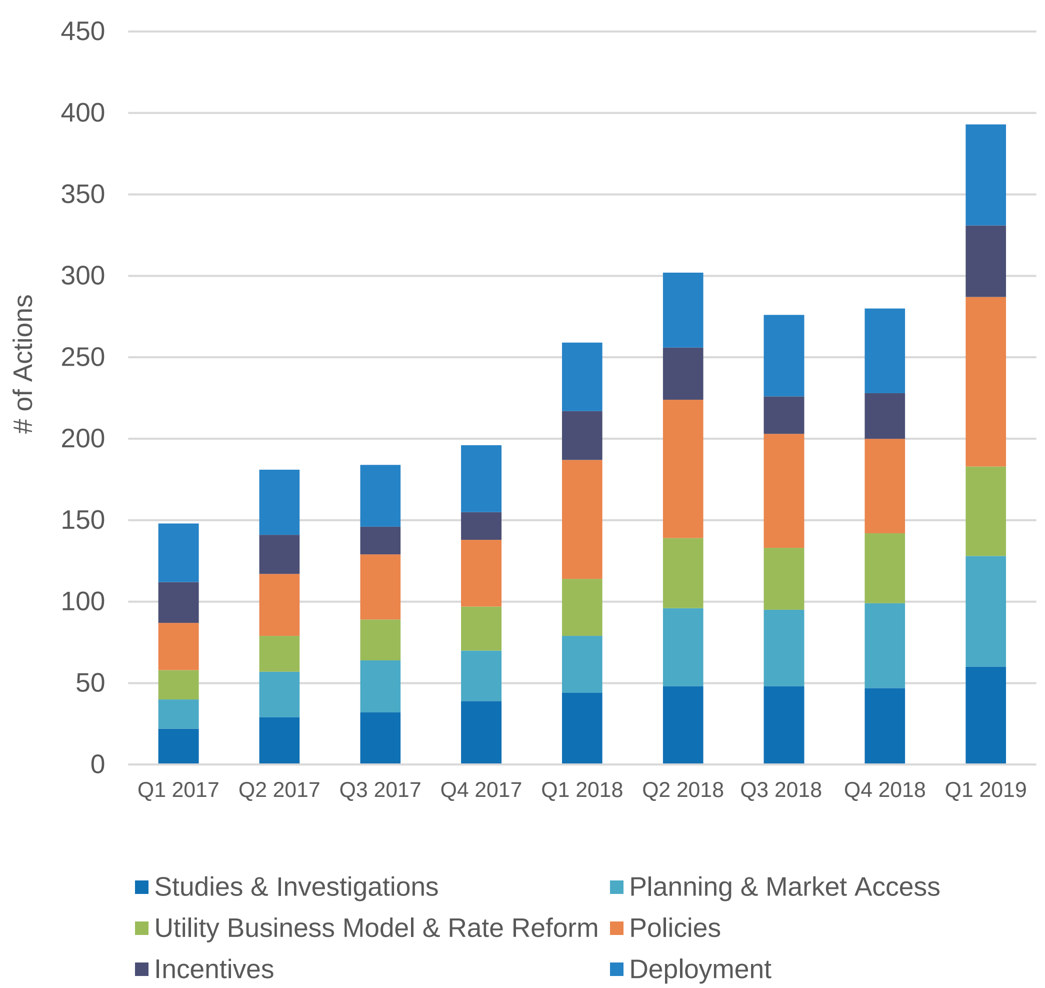
Grid modernization activity jumped up in Q1 2019, with many new bills related to grid modernization being introduced during the quarter. A total of 395 actions were taken in Q1 2019, with activity increasing in all six report categories. Activity also increased by 53% over Q1 2018 (259 actions) and by 167% over Q1 2017 (148 actions).

Figure 2. Q1 2019 Action on Grid Modernization, by Number of Actions



The states taking the greatest number of actions related to grid modernization in Q1 2019 are shown in Figure 4. New York, California, and Massachusetts took the most action during the quarter, followed by Minnesota, New Jersey, Hawaii, and New Hampshire. A total of 44 states plus DC took action on grid modernization during Q1 2019. The greatest amounts of grid modernization activity during the quarter were concentrated in the Northeast and Southwest.

Figure 3. Total Number of Grid Modernization Actions by Quarter



Of the 395 actions taken in Q1 2019, 162 were legislative, while 233 were regulatory. Although the majority of bills under consideration will not ultimately be enacted, these actions do indicate where policymakers are considering various aspects of grid modernization.

Figure 5 displays the most active states of Q1 2019 by the status of each action taken (for bills, I = introduced, P1/P2 = passed one or both chambers, E = enacted, D = dead). For the purposes of this graph, each individual action is assigned a status, so bills containing several different grid modernization components may be counted multiple times. The graph is not intended to be a precise representation, but rather to show that while some states may be considered very active, fewer actions led to policy changes or technology deployments.

Figure 4. Most Active States of Q1 2019

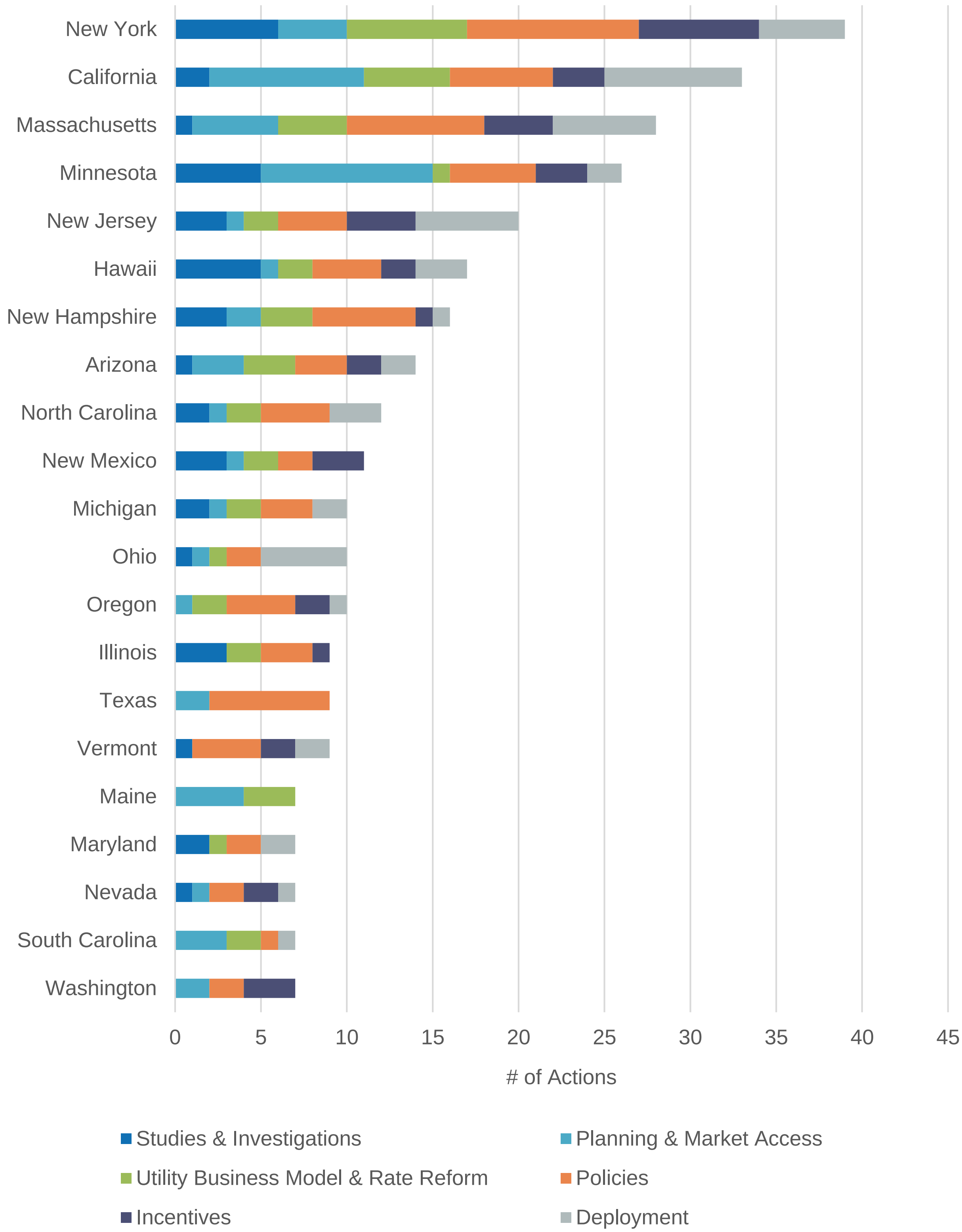


Figure 5. Most Active States of Q1 2019, by Action Status

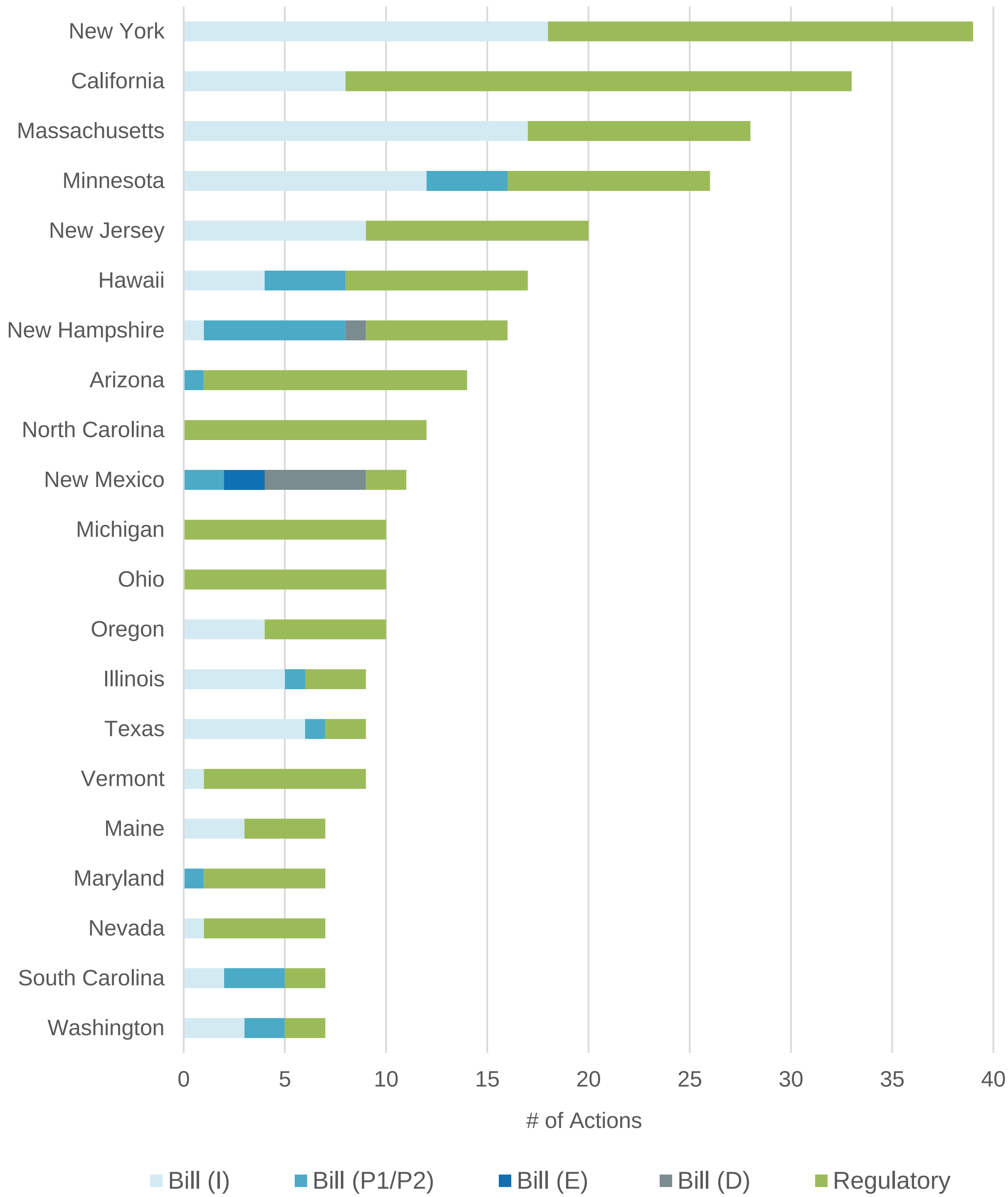
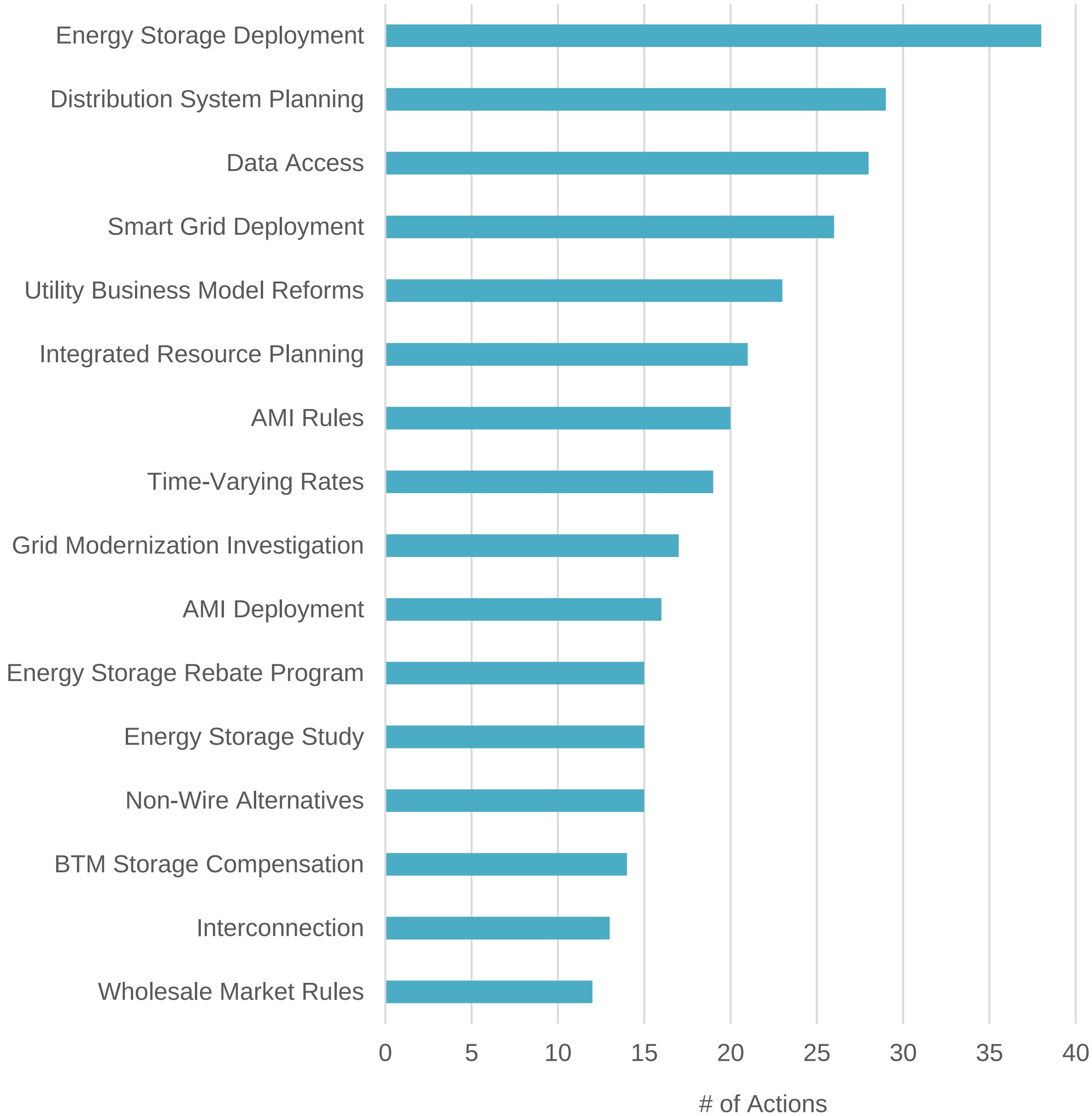


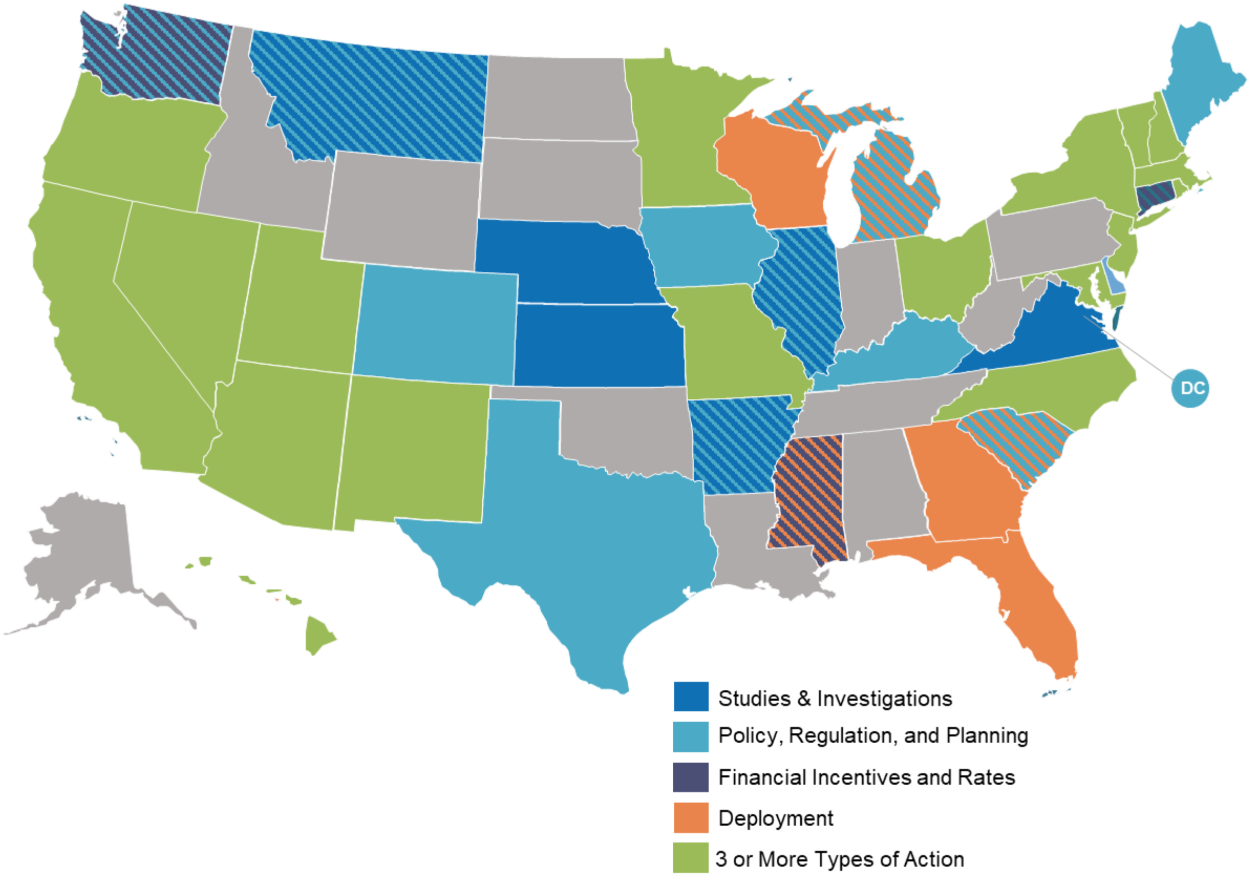
Figure 6. Most Common Types of Actions Taken in Q1 2019



The most common types of actions taken during Q1 2019 related to energy storage deployment (38), followed by distribution system planning (29) data access policies (28), smart grid deployment (26), and utility business model reforms (23).

Of the 44 states taking grid modernization action in Q1 2019, 38 states took action on energy storage. The most common types of energy storage actions were related to energy storage deployment requests, distributed energy resource and distribution system planning efforts, financial incentives, and energy storage studies. Several states are also examining energy storage as part of grid modernization investigatory proceedings, considering energy storage procurement targets or clean peak standards, reviewing energy storage compensation and interconnection rules, and energy storage cost recovery rules.

Figure 7. Q1 2019 Action on Energy Storage, by Type of Action



Box 1. Top Five Grid Modernization Actions of Q1 2019

New Hampshire PUC Staff Releases Final Grid Modernization Report

The New Hampshire Public Utilities Commission Staff released its long-awaited grid modernization report in February 2019, following the efforts of a grid modernization working group that concluded in 2017. The report recommends that utilities file integrated distribution plans that include both grid modernization initiatives and least-cost integrated resource plans.

Oregon PUC Opens Distribution System Planning Proceeding

Oregon regulators opened a proceeding on distribution system planning in Q1 2019, following the Commission Staff's recommendation that the Commission undertake an investigation on distribution system planning and develop a transparent, robust, and holistic planning process. The Staff published a white paper with a draft scope and proposed outcomes for the investigation.

Hawaii PUC Staff Files Performance-Based Regulation Recommendations

The Hawaii Public Utilities Commission Staff filed its performance-based regulation recommendations in February 2019. The Staff recommended new performance incentive mechanisms based on interconnection experience, customer engagement, and distributed energy resource asset effectiveness. The Staff's proposal also includes a five-year multi-year rate plan period and a revised earnings sharing mechanism.

Ameren Missouri Proposes $6.3 Billion Smart Energy Plan

Ameren Missouri filed for approval of its $6.3 billion Smart Energy Plan in February 2019. The five-year plan includes investments in AMI, distribution automation, cybersecurity, and distributed solar paired with energy storage, as well as grid reliability and wind energy investments. Pursuant to S.B. 564, enacted in 2018, the utility's rates are frozen until April 2020.

Virginia Regulators Direct Dominion Energy to Refile Grid Modernization Plan, Appalachian Power Withdraws Plan

In January 2019, Virginia regulators issued an order rejecting the majority of Dominion Energy's grid modernization plan (approving $154.5 million of the proposed $1.5 billion in Phase I investments) and directing the utility to refile the plan. Following this decision, Appalachian Power withdrew its proposed grid modernization plan to revise it based on the Commission's guidance to Dominion.

Box 2. Top Grid Modernization Trends of Q1 2019

Regulators Seeking Greater Realization of Advanced Metering Potential

As utilities request approval to deploy advanced metering infrastructure (AMI), regulators in several states are indicating that the functionality of these meters needs to be more fully utilized in order to justify the expenditures. The Virginia Corporation Commission rejected Dominion Energy's AMI deployment proposal in January 2019 because the utility did not provide a plan to maximize the potential of AMI. Appalachian Power, which also requested approval for AMI deployment in Virginia, filed supplemental testimony in order to address the AMI concerns cited in Dominion's case, but later withdrew its plan with an intent to refile after addressing the Commission's standards. In Hawaii, regulators approved HECO's request to deploy AMI, but directed the utility to develop an advanced rate design strategy to help maximize the benefits of AMI. National Grid filed its proposed AMI implementation plan in New York, following a 2018 settlement that included a stakeholder process to develop the plan.

States Incorporating Energy Storage into Existing Policy and Incentive Frameworks

Several states took actions to incorporate energy storage into existing policies during Q1 2019. Some states, including Arkansas, California, New Hampshire, and South Carolina, considered the net metering eligibility of distributed generation systems paired with energy storage. North Carolina, Oregon, and South Carolina are addressing how the Public Utility Regulatory Policies Act (PURPA) applies to energy storage facilities, while a number of states considered legislation allowing renewable energy projects paired with energy storage to be eligible for renewable portfolio standard compliance. Other policy areas states are addressing are: updating interconnection rules to include energy storage systems and advanced inverter capabilities; considering requirements for evaluation of energy storage options in integrated resource planning; and extending solar energy incentives to apply to energy storage projects.

Efforts Spreading to Expand Customer Data Access

A growing number of states are working to increase access to customer energy usage data, both for customers themselves, and with customer permission for third-party designees, as well as aggregated data. Bills expanding customer data access were under consideration in at least nine states during Q1 2019. The Montana State Legislature enacted a bill requiring data access for customers and customers' designees and authorizing utilities to disclose anonymous, aggregated data. Utah lawmakers enacted legislation requiring utilities to provide non-residential customers with access to their own usage data, but authorizing fees for accessing this data. Data access legislation also advanced in New Hampshire, while the North Carolina Utilities Commission opened a new proceeding to develop data access rules and the Vermont Public Utility Commission approved a data access standard put forward by Green Mountain Power and Efficiency Vermont.

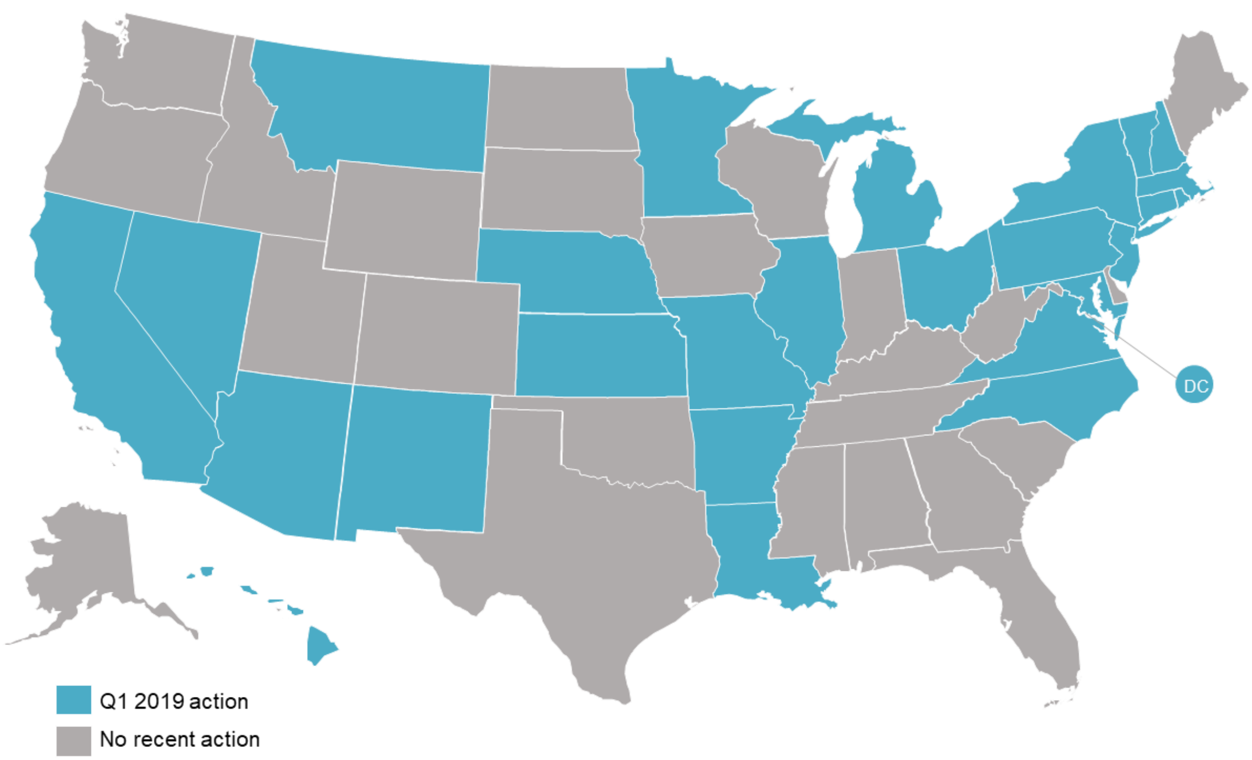
STUDIES AND INVESTIGATIONS

Key Takeaways:

- In Q1 2019, 26 states plus DC took action to study or investigate issues related to grid modernization, energy storage, microgrids, utility business models, and rate reform.
- State legislators introduced 36 bills related to grid modernization studies in Q1 2019.
- The New Hampshire Public Utilities Commission Staff published its final grid modernization report and recommendations.

Several states addressing grid modernization are citing a need for greater information to inform the legislative and regulatory processes. Many states do not yet have significant experience with grid modernizing technologies, and in some cases, these technological advancements are prompting an examination of the state's overall vision for the electric grid and an analysis of potential policy mechanisms to achieve that vision. States are informing the policy process by commissioning studies and investigations into technologies, as well as the regulatory practices and structures tied to their deployment.

Figure 8. Action on Grid Modernization Studies and Investigations (Q1 2019)



In Q1 2019, 26 states plus DC took actions related to grid modernization studies and investigations. State legislators introduced a total of 36 new bills during Q1 2019 requiring a study or investigation into elements of grid modernization. In Kansas, the state legislature enacted a bill in early April requiring a study of a variety of grid modernization issues, including ratemaking practices, performance-based regulation, integrated resource planning, energy storage, and microgrids. Meanwhile, Virginia lawmakers enacted bills forming stakeholder groups to examine advanced metering infrastructure, data access, and time-varying rates. Six additional bills have passed one legislative chamber. Proposed legislation in Illinois and Minnesota initiate energy storage studies, while a New Hampshire bill calls for a study of the legal challenges to microgrids in the state.

Box 3. Categorizing Studies and Investigations

Actions included within Studies and Investigations do not include a defined policy proposal or a directive to make a policy or regulatory change. Once a specific proposal is introduced, that action will be included in the more specific category pertaining to that particular type of change, such as Grid Modernization Planning, Utility Business Models, Rate Reforms, or the specific categories listed under Grid Modernization Policies, such as interconnection rules, changes to renewable portfolio standards, energy storage targets, and AMI rules.

The New Hampshire Public Utilities Commission Staff submitted a final grid modernization report with recommendations, following a stakeholder proceeding that concluded in 2017. A central recommendation of the report is for utilities to submit integrated distribution plans, including both grid modernization initiatives and their least cost integrated resource plans. The report goes on to identify objectives, capabilities, and functionalities upon which utilities should base the assessments of their distribution systems.

Figure 9. Action on Studies and Investigations by Topic (Q1 2019)

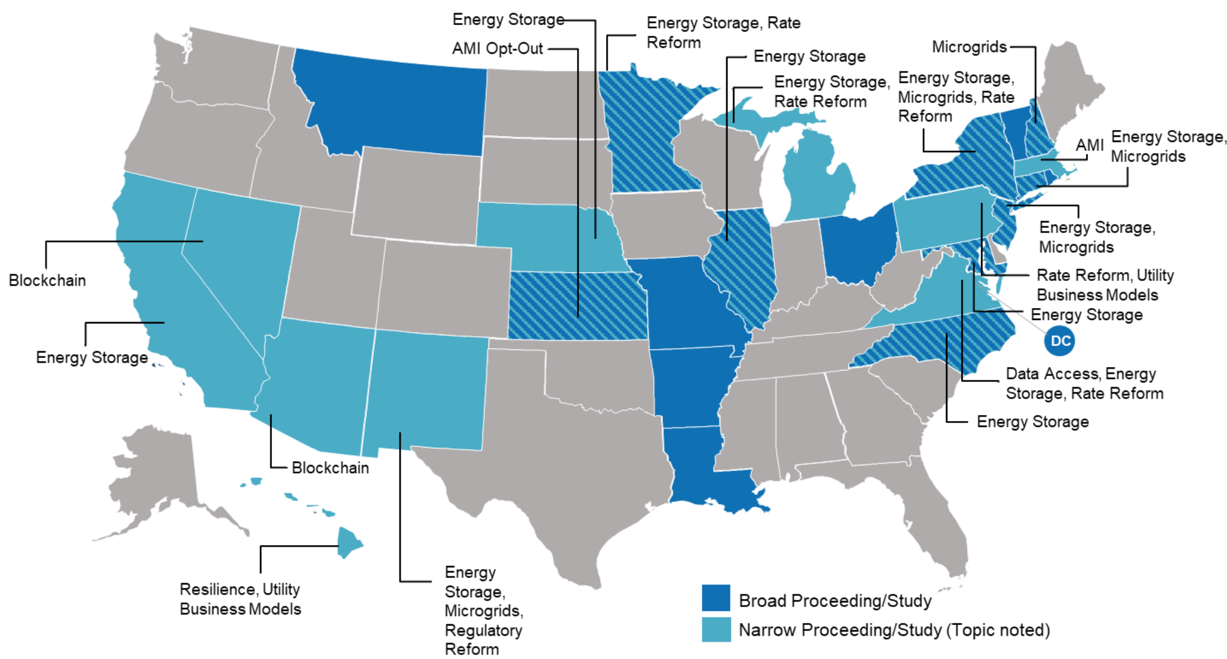


Table 2. Updates on Grid Modernization Studies & Investigations (Q1 2019)

State	Type of Study	Description	Source
AR	Distributed Energy Resources, Grid Modernization	In November 2017, the Arkansas Public Service Commission expanded the scope of a generic proceeding on renewable DG to more broadly consider policy changes related to DERs, as well as several specific AMI data access questions. In July 2018, the Commission issued an order, establishing a list of issues to be addressed during the course of the proceeding. These list includes many specific topics within the broader categories of DER aggregation, rate structure and rate design, low-income customer participation, advanced technology, and distribution system planning and integrated resource planning. The Commission will schedule an initial educational workshop on DER and grid modernization issues. The Commission accepted comments on the grouping of issues to be addressed in the proceeding and additional issues, the order and prioritization of these issues, means of addressing and building consensus on these issues, the expertise necessary to address these issues, and possible timeframes for events. The Commission also deferred action on the electric cooperatives' request for exemption from this proceeding until after the educational workshop.	Docket No. 16-028-U Order No. 10
AZ	Blockchain	In July 2018, the Arizona Corporation Commission opened a docket to investigate the role of blockchain technology in Arizona, at the request of Commissioner Tobin. No action has yet occurred in the docket. In February 2019, the Commission Staff filed a memo proposing that a workshop be held in June 2019 to begin reviewing blockchain technology.	Docket No. AU-00000A-18-0261
CA	Energy Storage	A.B. 1144 requires the California Public Utilities Commission, by January 1, 2021, to prepare and submit to the legislature a report that provides guidance to local publicly owned electric utilities and the Independent System Operator on measures that remove barriers to the participation of energy storage resources in the capacity, energy, and ancillary services markets.	A.B. 1144 (I)
	Microgrids	Existing law requires the California Public Utilities Commission to prepare an annual report to the Governor and Legislature with recommendations for a smart grid, the plans and deployment of smart grid technologies by the state's utilities, and the costs and benefits to ratepayers. A.B. 1503, as amended requires the report, starting in 2022 to describe workforce opportunities in the areas of	A.B. 1503 (I)

		distributed energy and microgrids, including emerging energy jobs and professions and the costs and benefits to the ratepayers.	
CT	Energy Storage	H.B. 6237 requires a study of energy storage projects and DG in the state to be conducted, including recommendations on pilot programs, incentives, and if changes to state energy procurements should be made to promote storage.	H.B. 6237 (I)
	Grid Modernization	H.B. 6238 requires a study of grid modernization in the state to be conducted, including a review of recommendations from the Public Utilities Regulatory Authority's grid modernization docket and recommendations for upgrading wires, transformers, substations, and metering technology to facilitate improved voltage parameters and two-way electricity flow.	H.B. 6238 (I)
	Grid Modernization, Rate Reform	In November 2017, the Public Utilities Regulatory Authority (PURA) opened a proceeding to investigate the state of the electric distribution companies' distribution systems and plans, near and long term needs of the distribution system, and whether any new or modified planning objectives, metrics, solutions, performance incentives, oversight and/or procurement mechanisms should be implemented. Focus areas highlighted by the PURA include DER integration; modernizing data sensing, analytics, control, and communications; alternatives to traditional capacity solutions; and rate design. The first phase of the proceeding focused on establishing the PURA's regulatory framework for grid modernization and examined three questions: (1) What are the key cost drivers associated with maintaining and modernizing the electric distribution system? (2) To what extent is customer electric demand changing in the near-term and long-term, and how can distribution system planning efforts best respond to changing customer demand? and (3) What functions do grid modernization technologies serve and how can these technologies be deployed to most effectively and efficiently meet the needs of the electric distribution utilities and customers, in light of the evolving distribution grid and electric system? A technical meeting was held in June 2018, focusing on Topic 1, while Topics 2 and 3 were addressed at technical meetings in July and October 2018. A public hearing was held in late October 2018, with briefs accepted in November. A decision had not yet been issued as of early April 2019.	Docket No 17-12-03

	Microgrids	H.B. 6235 requires a study of microgrids in the state to be conducted, including recommendations on criteria and priorities for promoting microgrids.	H.B. 6235 (I)
DC	Grid Modernization	In June 2015, the DC Public Service Commission (PSC) initiated a proceeding to identify technologies and policies that can modernize its energy delivery system for increased sustainability, reliability, efficiency, cost-effectiveness, and interactivity. In January 2017, the staff presented its Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) report. In February 2018, the PSC adopted a MEDSIS vision statement and determined that it would conduct a request for proposals for a MEDSIS consultant. The PSC selected the Smart Electric Power Alliance (SEPA) to serve as its consultant. In June 2018, SEPA led a MEDSIS technical conference in which stakeholders were able to provide input on whether a system assessment was needed and what working groups should be formed in Phase 2 of the MEDSIS Initiative. SEPA filed its recommendations, which the Commission approved in an August 2018 decision. Specifically, SEPA recommended against a full system assessment at this time, and recommended the formation of six working groups: (1) Data and Information Access and Alignment, (2) Non-Wires Alternatives to Grid Investments, (3) Future Rate Design, (4) Customer Impact, (5) Microgrids, and (6) Pilot Projects. A later decision, filed in September 2018 tasked the Non-Wires Alternatives working group with proposing a definition for "smart inverter" and considering utility ownership of DERs, like energy storage devices, and submit its recommendations for the Commission's consideration. A draft report on the working group recommendations was filed in mid-April 2019. The Commission will host a two-day joint working group meeting in late April 2019 to facilitate stakeholder and public input on the draft MEDSIS working group recommendations.	Formal Case No. 1130 MEDSIS website MEDSIS Staff Report Order No. 19432 (August 2018) Order No. 19692 (September 2018) Draft Working Group Recommendations (April 2019)
HI	Microgrids, Resilience	H.B. 1583, as introduced, requires the Department of Education to establish a pilot program in which various schools are provided with renewable energy systems that are capable of providing backup power in the event of a natural disaster or other similar emergency; and requires the Public Utilities Commission to open a proceeding to incentivize the implementation of these renewable energy systems. The House passed the bill in February 2019. The Senate amended the bill to	H.B. 1583 (P1)

	authorize the Departments of Transportation and Education to evaluate the feasibility, costs, and benefits of renewable energy microgrid systems to provide backup power in the event of a natural disaster or other similar emergency, and authorize the natural energy laboratory of Hawaii authority to establish a microgrid demonstration project. Further, the amended bill requires the Public Utilities Commission to incorporate findings from public agency microgrid evaluations into its microgrid service docket and consider ways to incentivize the installation in public facilities of renewable energy systems that can provide backup power in the event the broader electric grid cannot provide power. The Senate passed the bill and sent it back to the House in April. The House disagreed with the Senate's amendments and returned it to the Senate.	
Resilience	H.B. 436 and S.B. 609 establish a Homeland Security and Resiliency Council, which is tasked with establishing strategies, goals, priorities, and recommendations to improve the security and resiliency of the electric grid and other critical infrastructure. The Council must submit a report summarizing its findings, recommendations, and the status of actions to enhance electric grid and other critical infrastructure sector security and resiliency to the Governor, Legislature, and Mayor and County Council of each county no later than 20 days prior to the convening of the regular session of 2020, and every two years thereafter. The Senate passed S.B. 609 in March 2019.	H.B. 436 (I) S.B. 609 (P1)
Resilience	H.B. 856 directs the Department of Business, Economic Development, and Tourism, in coordination with counties, to develop a plan to ensure critical infrastructure locations will have access to electricity after natural disasters. This includes recommending grid resiliency improvements for each infrastructure location, as well as for electrically isolated communities. Grid resiliency is defined as including DERs, battery storage, and microgrids.	H.B. 856 (I)
Resilience	S.B. 1159 establishes a Homeland Security and Resiliency Council, which is tasked with establishing strategies, goals, priorities, and recommendations to improve the security and resiliency of the electric grid and other critical infrastructure.	S.B. 1159 (I)
Utility Business Model	H.B. 1700 of 2016 appropriated funds for the Hawaii Energy Office to commission a study of alternative utility and regulatory models to enable	H.B. 1700 (2016) Study Website

		the state to (1) meet its energy goals; (2) maximize consumer savings; (3) enable a competitive distribution system; and (4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation. The Energy Office selected London Economics International, LLC to lead the project, and scheduled three rounds of community meetings in each of the counties. The first round of community meetings was held in mid-October 2017 and focused on the topic of utility ownership and the utility's role in meeting community and state goals. The second round of meetings were held in June 2018 and focused on utility regulatory models.	
IL	Energy Storage	H.B. 2926 and S.B. 1792 require the Illinois Commerce Commission to select an independent consultant to conduct a study of the costs and benefits of energy storage systems for ratepayers and customers. The study would need to be completed by December 31, 2019.	H.B. 2926 (I) S.B. 1792 (P1)
	Energy Storage	H.B. 2966 requires the Corporation Commission and the Illinois Power Agency to conduct a study of the costs and benefits of various energy storage deployment options in Illinois, including recommendations on deployment targets, which the Illinois Power Agency would need to include in its 2021 procurement plan.	H.B. 2966 (I)
	Grid Modernization	In March 2017, the Illinois Commerce Commission opened the "NextGrid" proceeding following the passage of legislation in December 2016 that makes comprehensive changes to various aspects of Illinois energy policy. This is a collaborative process between stakeholders and involves a broad array of topics. Seven working groups have been established, each addressing topics potentially pertaining to grid modernization: (1) New Technology and Grid Integration, (2) Electricity Markets, (3) Customers and Community Participation, (4) Regulatory, Environmental, and Policy Issues, (5) Metering, Communications, and Data, (6) Reliability, Resiliency, and Cyber Security, and (7) Ratemaking. The NextGrid process officially began in late September 2017 with a kickoff conference in Chicago. The working groups submitted draft reports in August 2018, most of which contained discussions pertaining to grid modernization. Working Group 1's report discusses microgrids and distribution system planning. Working Group 2's report discusses AMI. Working Group 4's report discusses data access, time-varying rates, energy storage, and grid modernization impacts on very large customers.	Docket No. 17-0142 NextGrid Draft Final Report

		Working Group 5's report discusses real-time pricing and its interaction with advanced metering. Working Group 7's report discusses time-varying rates and performance-based regulation. A draft final report compiling the working group reports was published in December 2018. Comments on the final report were published in early January 2019. The release of the final version of the NextGrid report has been delayed due to a lawsuit regarding procedural issues.	
KS	AMI Opt-Out	In May 2018, following several customer complaints related to AMI opt-out rules, the Kansas Corporation Commission directed Westar and Kansas City Power & Light to file new or updated tariffs allowing customers to opt out of AMI installation at the customer's expense. The Commission also opened a general investigation docket to fully investigate the parameters and intricacies of AMI opt-out programs in July 2018. In March 2019, the Commission issued an order closing the investigation and not requiring any further action from utilities; the order specifically declined to require utilities to create inventories of analog meters or create any further AMI opt-out programs.	Docket No. 15-WSEE-211-COM Order on Reconsideration Docket No. 19-GIME-012-GIE
	Grid Modernization, Integrated Resource Planning, Utility Business Model	S.B. 181 creates an energy policy task force to review many aspects of energy policy, including ratemaking processes and options like performance-based regulation, cost recovery through surcharges and riders, cyber and physical security, the value of a utility integrated resource planning process that requires state regulatory approval, and the impact of advanced energy technologies (including energy storage, microgrids, electric vehicles and charging stations, transactive energy, and customer generation) on utility reliability and rates.	S.B. 181 (I)
	Grid Modernization, Integrated Resource Planning, Rate Design, Utility Business Model	H.B. 2231 and S.B. 69 require the Corporation Commission to conduct a study of a wide variety of electric issues in Kansas. The study is to be conducted by an independent, expert organization selected by the legislative coordinating council, with input from stakeholders. The study is to evaluate the effectiveness of current ratemaking practices and consider whether cost recovery through riders and surcharges has led to rising electricity prices. The study is to consider any performance-based regulation, economic development incentives, price-cap regulation, and non-traditional ratemaking methods, as well as whether competitive markets for retail electricity could benefit Kansas consumers. The study is also	H.B. 2231 (I) S.B. 69 (E)

		to address whether allowing utilities to recover costs through surcharges and riders has contributed to increased wholesale and retail electricity prices. The bill also requires the study to look at how cyber and physical grid security efforts may affect electric rates and whether Kansas consumers could benefit from increased access to electric vehicles and charging, microgrids, battery storage, customer generation, and transactive energy. A substituted version of the bill was passed by the Senate; the substituted version adds consideration of integrated resource planning to the list of issues to be studied. The bill was approved by the Governor on April 10, 2019.	
LA	Grid Modernization	In February 2018, the New Orleans City Council opened an inquiry into establishing a smart cities initiative for the city and directing Entergy New Orleans to report on grid modernization matters. The Council's resolution directed Entergy New Orleans to file a report detailing available grid modernization technologies and how such modernization could be implemented by the utility. The Council Utility Advisors are directed to prepare a report on other aspects of technology integration that could be achieved with a smart cities initiative. In April 2018, Entergy New Orleans filed its grid modernization report. The utility hired a third party to conduct an asset-specific engineering study evaluating 467 circuits across the Entergy system. Based on this study, Entergy New Orleans is developing five grid modernization projects to increase grid reliability, which will include the deployment of 537 smart devices (noted as regulators and capacitors) and 42 self-healing networks. The City Council approved a resolution in December 2018 directing the Utility Advisors to propose a roadmap for achieving electric grid modernization and the Smart City initiative goals with a draft "Smart Audit" procedure. The resolution also merged Docket No. 18-02 regarding electric vehicles with the smart cities docket (Docket No. 18-01). Entergy New Orleans, EV Louisiana, and the Alliance for Affordable Energy submitted their lists of electric vehicle issues for consideration in the proceeding in late February and early March 2019.	City Council Docket No. 18-01 Entergy New Orleans Grid Modernization Report
MA	AMI	H. 2840 establishes a special commission to investigate the results of National Grid's Worcester Smart Meter Pilot Program, which ended at the end of 2018. The commission is to examine the costs and savings associated with the program and determine whether National Grid ratepayers should bear the costs for the program.	H. 2840 (I) H. 2888 (I)

MD	Energy Storage	H.B. 1414, enacted in May 2017, requires the Power Plant Research Program to conduct a study on the state's Renewable Portfolio Standard. The study is to include a review of the program's history, implementation, overall costs and benefits, and several other issues. The bill also requires energy storage to be part of the study, specifically addressing whether energy storage should be encouraged through a procurement, production or installation incentive; the advisability of providing incentives for energy storage to increase the hosting capacity of renewable energy on-site; and the costs and benefits of energy storage under future goals scenarios. The study group has primarily focused two tasks to date, both of which are focused on the functioning of the current RPS. The study group issued an RFP in October 2017 to find a party to complete the remaining tasks in the study, including those related to energy storage. Though the RFP states that the contractor will rely principally on the energy storage study conducted under H.B. 773 (published in December 2018). An interim report was filed in December 2018 and a final report is due by December 1, 2019. A webinar was held in November 2018 to update parties on the progress of the study.	RPS Study Work Group Website H.B. 1414 (2017)
	Energy Storage, Grid Modernization	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding is addressing rate design, electric vehicles, competitive markets and customer choice, the interconnection process, energy storage, and distribution system planning. The Public Staff has organized working groups to study (1) rate design, (2) competitive markets and consumer choice, (3) interconnection, and (4) energy storage. In January 2019, the Energy Storage working group participants from PC 44 developed a short term Proof of Regulatory Concept Program to test regulatory and business models for energy storage. The working group consensus is to adopt a learning by doing approach, where the utilities will solicit four commercial and regulatory models (utility owned, third party owned, service agreements, and Virtual Power Plant) to evaluate efficacy of energy storage assets under multiple application and ownership models. The Commission held a comment period and a	Public Conference No. 44

		legislative-style hearing to consider the proposal during Q1 2019.	
MI	Demand Response	In November 2018, the Michigan Public Service Commission opened this docket to investigate demand response aggregation issues, including: (1) whether the ability to aggregate demand response for customers of alternative energy suppliers (AES) for bidding into RTO markets should be limited to AES, or extended to non-AES third parties, (2) how to adequately track demand response resources being used for capacity demonstration purposes, (3) the appropriate treatment for aggregated demand response outside the capacity demonstration framework, and (4) appropriate reporting requirements for demand response and aggregation. The Commission Staff is ordered to file a report on these issues by May 30, 2019.	Docket No. U-20348
	Distribution System Planning, Integrated Resource Planning	In February 2019, at the request of the Governor, the Michigan Public Service Commission (PSC) opened a docket to conduct an assessment of the supply and deliverability of natural gas, electricity, and propane in Michigan, as well as contingency plans. The assessment will include a review of distribution, transmission, and generation planning by both natural gas and electric utilities. The PSC Staff requested comments on the proposed assessment in February 2019. The PSC issued a scheduling memo in early March 2019, along with an outline for the final report to be published by September 13, 2019.	Docket No. U-20464
MN	Energy Storage	H.B. 165 and S.B. 100 direct the Commissioner of Commerce to hire an independent consultant to conduct a study analyzing the costs and benefits of energy storage systems in Minnesota. The study would be due by December 31, 2019, and the bills appropriate $150,000 for the study.	H.B. 165 (I) S.B. 100 (P1)
	Energy Storage	Among other provisions, H.B. 1165 requires the Commission of Commerce to hire an independent contractor to prepare a report analyzing the costs and benefits of energy storage.	H.B. 1165 (I) S.B. 1608 (I)
	Grid Modernization	The Public Utilities Commission (PUC) opened a docket in May 2015 to consider the development of policies related to grid modernization. The proceeding features broad stakeholder engagement and numerous workshops. In April 2017, the PUC issued a request for comments from Xcel Energy, Minnesota Power, and Otter Tail Power (cooperative and municipal utilities were encouraged but not required to respond) related to	Docket No. 15-556

	the following questions: (A) How do Minnesota utilities currently plan their distribution systems? (B) What is the status of each utility's current plan? and (C) Are there ways to improve or augment utility planning processes? In April 2018, the Commission Staff released a briefing paper, setting forth a proposed procedure and schedule for developing utility-specific integrated distribution plans. According to the Staff's schedule, Xcel Energy and the Dakota Electric Association would have until November 1, 2018 to submit their integrated distribution plans, and Otter Tail Power and Minnesota Power would have until November 1, 2019. The PUC held a meeting in April 2018 to discuss the actions the Commission should take on distribution system planning for each of the utilities. No significant action took place in Q3 2018.	
Microgrids	H.B. 1833 and S.B. 2067 require the Commissioner of Commerce to conduct a study to develop a strategy for the state to advance the commercial application of microgrids. The study must focus on how the state can assist in integrating microgrids ready for commercial application. The study must also evaluate options to fund microgrid pilot projects. The study is to be completed by February 15, 2020.	H.B. 1833 (I) S.B. 2067 (I)
Rate Reform	The Public Utilities Commission (PUC) initiated a stakeholder proceeding in July 2015 to consider alternative rate designs for Xcel Energy. The proceeding has held workshops and heard from various speakers about alternative rate design implementation across the country. In April 2017, Xcel Energy presented on its ongoing development of an alternative rate design pilot, and the PUC solicited comments on the pilot and whether this generic docket should continue in parallel to the Xcel pilot development. The PUC received comments from stakeholders during May 2017, and no parties appear to be opposed to Xcel developing a pilot, or leaving the current docket open after Xcel files its pilot program. Xcel is developing its alternative rate design pilot with a group of stakeholders, facilitated by the Great Plains Institute and the Center for Energy and Environment. In February 2018, the Great Plains Institute filed its notes from the stakeholder meetings, demonstrating that Xcel designed its TOU pilot in direct response to the requests, goals, and objectives of the stakeholders involved. No significant action took place in Q1 2019.	Docket No. 15-662

MO	Distributed Energy Resources, Rate Reform	In March 2017, the Missouri Public Service Commission (PSC) opened a proceeding to gather information on issues including AMI installation, PACE financing programs, and alternative rate design proposals. A workshop was held in May 2017, where these issues were discussed. In July 2017, the Commission Staff filed a report with recommended next steps. The report recommends that workshops be held to discuss several issues, including new rate designs, particularly time-of-use rates and inclining block rates. However, as no significant issues related to AMI were identified during the comment period or workshop, the Staff did not recommend additional workshops on AMI. Workshops on DER issues were held in November 2017 and January 2018. In April 2018, the Commission Staff released a report on DER issues. The report states that distributed storage is eligible for inclusion in Missouri's demand-side management program, which would allow utilities to recover costs for distributed storage. In May 2018, the PSC Staff published a draft rule for comment, and a workshop was held to discuss the rule. In late June 2018, the PSC Staff filed an updated version of the draft rule for comment. The current version requires utilities to maintain a database of current DERs on their grids, assess the market potential for DERs as part of their triennial compliance filings, and evaluate DERs as part of the resource planning process, including their integration with the transmission and distribution system. Several parties filed comments on the draft rule in July 2018. No action has been taken in this docket during 2019.	Docket No. EW-2017-0245 July 2017 Staff Report April 2018 Staff Report June 2018 Draft Rule
MT	Grid Modernization	In April 2018, NorthWestern Energy held the first meeting of its Customer Vision stakeholder group. The group will address potential products and services customers would be interested in, pricing models that align utility and customer needs, and the future of the power grid. The group also met in May, June, and September 2018, with presentations about Minnesota's e21 Initiative, the Illinois NextGrid process, and Green Mountain Power's programs. An October 2018 meeting discussed Ontario's electricity pricing and rate design, as well as NorthWestern Energy's infrastructure initative goals and alternatives. A meeting was held in November 2018 to discuss a decoupling proposal and force-field analysis. A meeting was held on February 1, 2019, with presentations on decoupling, energy efficiency opportunities, providing a true customer experience, and keeping customer focus in technology projects.	Customer Vision Stakeholder Group

NC	Energy Storage	In a proceeding in which Duke Energy Progress is seeking a Certificate of Public Convenience and Necessity for a microgrid solar and battery storage facility, the Public Staff cited concerns about accurately quantifying the cost effectiveness of the project, but ultimately recommended Commission approval. In its testimony, the Public Staff also recommended certain reporting requirements and urged the Commission to require a study performed either by a third party or by Duke Energy to estimate the ancillary service benefits battery storage can provide Duke's system, using sub-hourly modeling techniques. Duke Energy Progress and the Public Staff filed a joint proposed order in March 2019. The proposed order approves the project subject to certain conditions, including reporting requirements and a requirement that Duke Energy conduct the study of ancillary service benefits of battery storage using sub-hourly modeling techniques.	Docket No. E-2 Sub 1185
	Grid Modernization	Executive Order 80, signed in October 2018, requires the North Carolina Department of Environmental Quality (DEQ) to develop a Clean Energy Plan that encourages the utilization of clean energy technologies, including energy efficiency, solar, wind, energy storage, and other innovative technologies. The Plan must also examine the integration of those resources to facilitate the development of a modern and resilient electric grid. The DEQ must complete the Plan by October 1, 2019. The DEQ initiated a stakeholder process with the help of the Regulatory Assistance Project and the Rocky Mountain Institute to assist in developing the Plan. One workshop was held in February 2019 and two were held in April 2019. DERs, grid modernization, utility planning, and regulatory reform are among the topics being addressed in the workshops. Additional workshops and regional listening sessions are scheduled for Q2 2019. The DEQ expects to release the draft plan for public comment in August 2019, with the revised plan being reviewed and approved by the Climate Council in September 2019.	Executive Order No. 80 DEQ Website
NE	Energy Storage	L.B. 285 appropriates $200,000 to the Nebraska Power Review Board to conduct a study of electric transmission and distribution infrastructure, including identification of opportunities for energy storage to become part of the state's infrastructure and alleviate constraints.	L.B. 285 (I)
NH	Grid Modernization	In July 2015, the New Hampshire Public Utilities Commission (PUC) opened a docket on grid modernization, pursuant to H.B. 614 of 2015. The	Docket No. IR 15-296

	PUC convened a formal working group to develop recommendations on several issues, including distribution system planning, advanced metering functionality, rate design, customer data and education, and utility cost recovery and financial incentives. In March 2017, the working group submitted its final report to the Commission. In February 2019, the PUC Staff filed its final report and recommendations. The Staff recommend that utilities be required to submit integrated distribution plans (IDPs), including both grid modernization initiatives and their least cost integrated resource plans. The Staff identified objectives, capabilities, and functionalities for utilities to base their assessments of their distribution systems on. The functionalities include forecasting DER and demand growth, long-term system planning, scenario-based planning, DER locational value analysis, interconnection process, distribution system information sharing, integrated resource transmission and distribution planning, sensing and measurement, control, communications, asset management, integrated operational engineering and system operations, distribution system model, T-D interface coordination, real time DER operation, Volt/VAR and power quality management, fault management, cybersecurity, physical security, settlement procedures, DER portfolio management, DER sourcing (non-wires alternatives), market information sharing, and market oversight. The IDPs are to include a 10-year roadmap for meeting grid objectives and a 5-year implementation plan (capital investment/operational expense plan). The IDP is to include sections on common cost-effectiveness/business case assumptions, current system capabilities and processes, distribution system planning, architectural strategies and considerations, distribution operations, advanced meter functionality, rate design, cybersecurity and privacy, performance metrics, and rates and regulatory. The Office of the Consumer Advocate requested that the PUC issue an order of notice allowing for additional intervention requests and scheduling a prehearing conference. A technical session for discussion and questions on the report was held in March 2019.	NH Grid Modernization Working Group Document Repository Final Report (February 2019)
Microgrids	H.B. 183, introduced in January 2019, establishes a committee to study the legal changes necessary to allow for microgrids in the state. The committee is to report its findings and recommendations for proposed legislation by November 1, 2019. An amended version of the bill passed in March 2019.	H.B. 183 (P1)

	Microgrids	H.B. 238, introduced in January 2019, establishes a task force to study the application of microgrids in electricity supply. The task force is to report its findings and recommendations for proposed legislation by November 1, 2020.	H.B. 238 (D)
NJ	Energy Storage	A.B. 3723, enacted in May 2018, directs the Board of Public Utilities, in consultation with PJM Interconnection and stakeholders, to conduct an energy storage analysis. The study is to address a number of specific questions, quantify the potential costs and benefits of increasing energy storage and DERs in the state, and recommend ways to increase energy storage and DERs in the state. The Board of Public Utilities announced in October 2018 that it hired Rutgers University to conduct the study. Comments on several questions related to energy storage, included in A.B. 3723, were accepted until March 20, 2019. Comments were also accepted on the definition of energy storage, the discharge time duration to apply to the state storage capacity goals, what storage systems should be counted toward the state's goal, and how FERC Order 841 and PJM compliance affect energy storage in the state.	A.B. 3723 (2018) Press Release Energy Storage Working Group
	Grid Modernization	In May 2018, New Jersey's Governor directed the Board of Public Utilities to develop the 2019 Energy Master Plan. As part of this process, a stakeholder meeting on Building a Modern Grid was held in September 2018. Some of the topics being addressed by the Building a Modern Grid stakeholder group include the most critical steps and barriers to grid modernization, resource planning, integrated distribution planning, reliability and resiliency, performance metrics, rate design and tariff structures to support grid modernization, managing grid modernization costs, use of new technologies, role of AMI, data access, distribution monitoring systems, physical security and cybersecurity, and economic development and environmental justice issues related to grid modernization. The final plan is expected to be completed in June 2019.	Executive Order No. 28 Press Release Energy Master Plan Website
	Microgrids	A.B. 3931, introduced in May 2018, directs the Board of Public Utilities to study whether microgrids and electric generators assist in reducing the length of long-term power outages in the state. The study is also to provide recommendations to improve the resilience and reliability of the state's electric distribution system. The study would be due within six months of enactment of the bill.	A.B. 3931 (I)

NM	Energy Storage	H.B. 426 directs the New Mexico renewable energy transmission authority to study the adequacy of transmission pathways to support future renewable energy generation and storage over the next 10 years. The authority is also to contract with Sandia National Lab to use their tools and data for valuation, sizing, and placement of storage plants. The report is to include the size and location of short and long duration storage projects needed to support projected wind and solar deployment to reach 80% renewable energy penetration.	H.B. 426 (D)
	Microgrids	H.M. 71 is a House Memorial requesting the Energy, Minerals, and Natural Resources Department to establish a task force to study the efficacy of using smart, hybrid microgrids to accelerate clean and renewable energy. The task force would study how the government can assist utilities in attaining renewable portfolio standard goals by using smart, hybrid microgrids and how the government can require the inclusion of smart, hybrid microgrids and updated hybrid technologies in utility integrated resource plans. The House passed the Memorial in March 2019.	H.M. 71 (Passed)
	Regulatory Reform, Utility Business Model	In March 2017, the New Mexico Public Regulation Commission initiated an investigation to determine whether it should standardize or change its ratemaking policies. Specifically, the Commission is requesting information related to developing a standardized method for determining return on equity (ROE), whether ROE should be adjusted under an incentive/disincentive mechanism, providing access to proprietary software used by utilities to support positions in rate cases to all intervenors and staff, defining regulatory assets, and recovery of certain regulatory case expenses. Public workshops were held in September and November 2017, and the workgroup reports were submitted in January 2018. A public workshop was held in July 2018.	Docket No. 17-00046-UT
NV	Blockchain	The Commission opened a new docket in September 2018 at the request of Commissioner Pongracz. Specifically, the Commissioner requested an investigation into blockchain, and whether it could be used to better track portfolio energy credits associated with the state's Renewable Portfolio Standard. The Commission accepted comments through mid-April 2019, and a workshop will be held in early May 2019.	Docket No. 18-09008
NY	AMI, Time-Varying Rates	A.B. 3017 requires state agencies to publish a report on residential customer savings realized	A.B. 3017 (I)

	through the use of TOU tariffs and smart meters by December 1, 2020.	
AMI, Time-Varying Rates	S.B. 21, introduced in January 2019, requires the Public Service Commission to study and compile a report analyzing TOU rate plans offered by the state's electric and gas utilities. The study is also to include AMI recommendations, including how to incentivize AMI growth in the state and alternative ways to finance AMI installation.	S.B. 21 (I)
Energy Storage	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. The Roadmap does not contain policy changes itself but makes many recommendations on policy actions that could be undertaken in related proceedings. Three technical conferences to discuss the Roadmap were held in July and August 2018. In September 2018, the Public Service Commission (PSC) issued an environmental impact statement for the Roadmap, finding significant positive environmental impacts from the recommended policy actions in the Roadmap, with minimal adverse impacts. In December 2018, the PSC adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. The PSC also directed the Commission Staff to study how many MWs of peaking units could be economically replaced or repowered with energy storage without harming reliability. The Commission Staff and NYSERDA are also to develop a work plan for the Market Design and Integration Working Group by March 2019. The Staff is also to file a white paper by July 2019 on the environmental value component of the Value of Distributed Energy Resources (VDER) tariff for storage resources. As part of the roadmap, the PSC also directed the utilities to compile an inventory of unused, suitable land for non-wires alternatives, as well as interconnection upgrade costs for non-wires alternatives that can be included in RFPs. The Commission also directed the utilities to work with NYSERDA to develop a pilot DER data platform including anonymized customer and system data for DER developers. In February 2019, the PSC announced the formation of a working group on market design and integration, with a meeting held in March. On March 12, 2019, the market design and integration working group filed its work plan and schedule,	Docket No. 18-00516/18-E-0130 NYSERDA Website

		with monthly meetings planned through September 2020.	
	Energy Storage	S.B. 1611 directs the Public Service Commission to initiate a proceeding to determine appropriate targets for cost-effective energy storage systems. The outcome of the proceeding is to be implemented by January 1, 2023. The Commission is to consider a variety of policies to encourage storage deployment, and if a procurement target is determined to be appropriate, it is to be adopted by December 31, 2020. The Commission would be required to reevaluate the procurement targets every three years.	S.B. 1611 (I)
	Grid Modernization	A.B. 185, introduced in January 2019, establishes a Smart Grid Advisory Council, which would be tasked with conducting a study on the feasibility of establishing a statewide smart grid system. The smart grid system envisioned would include AMI, incorporate consumer products, promote DG, and protect privacy and security. The comprehensive bill includes provisions for cost allocation, workforce development, low-income programs, and more.	A.B. 185 (I)
	Microgrids	A.B. 6429 requires the Public Service Commission to develop recommendations on the establishment of microgrids in New York, including recommendations on which facilities and geographic areas would be appropriate for microgrids and possible funding mechanisms.	A.B. 6429 (I)
OH	Grid Modernization	The Public Utilities Commission of Ohio (PUCO) announced the launch of its PowerForward grid modernization investigation in March 2017. The purpose of the investigation is to chart a path forward for future grid modernization projects and innovative regulations that can improve the consumer experience. The PowerForward investigation included three phases, with Phase 1 beginning in April 2017 with a three-day “Glimpse of the Future” speaker series. The investigation continued in July 2017 with Phase 2: Exploring Technologies, and in March 2018 with Ratemaking and Regulation. In August 2018, PUCO released its final PowerForward Roadmap. The Roadmap provides a vision for the modernization of Ohio's grid and includes a series of recommended next steps to implement the vision. The Roadmap sets out four foundational tenets for grid modernization decisions: (1) Do no harm, (2) Provide Net Value to customers, (3) Create an environment that	Docket No. 18-1595-EL-GRD (PowerForward Collaborative) PowerForward Website PowerForward Roadmap

		fosters innovation, and (4) Enhance the experience for all. The Roadmap also establishes four desired outcomes: (1) A strong grid, (2) The grid as a platform, (3) A robust marketplace, and (4) The Customer's Way (an enhanced experience for customers). PUCO established separate dockets for the PowerForward collaborative and its spinoff workgroups (one on distribution system planning and one on data and the modern grid) in October 2018. As a first step, each electric distribution utility is to file grid architecture status reports by April 1, 2019. PowerForward Collaborative meetings were held on December 6, 2018 and February 14, 2019. The February agenda included presentations and discussion on electric vehicle charging and demand-side management, managed charging best practices, and metering requirements for electric vehicle rates.	
PA	Rate Reform, Utility Business Model Reform	In December 2015, the Pennsylvania Public Utility Commission (PUC) opened a proceeding to investigate alternative ratemaking methodologies. The PUC issued an order in March 2017, requesting further input from stakeholders on their experiences with different types of alternative rate methodologies, including decoupling, lost revenue adjustment mechanisms, straight fixed/variable pricing, surcharges and riders, choice of test years, multiyear rate plans, demand charges, standby and backup charges, and demand-side management performance incentives. The PUC also accepted comments regarding whether it should adopt policy statements identifying preferred alternative rate methodologies or initiate rulemakings to require specific methodologies. In May 2018, the PUC published a proposed policy statement. The statement includes 13 considerations for determining just and reasonable distribution rates that encourage efficiency and the use of DERs. These considerations are: (1) How rates align revenues with cost causation principles, (2) How rates impact the fixed utility's capacity utilization, (3) Whether the rates reflect the customer's demand, (4) How the rates limit or eliminate inter-class and intra-class cost shifting, (5) How the rates limit or eliminate disincentives for efficiency, (6) How the rates impact customer incentives for efficiency and DER use, (7) How the rates impact low-income customers, (8) How the rates impact customer rate stability principles, (9) How weather impacts utility revenue under the rates, (10) How the rate impact the frequency of rate case filings and regulatory lag, (11) How the rates interact with other surcharges and riders, (12) Whether the rate mechanism includes	Docket No. M-2015-2518883 Proposed Policy Statement

		appropriate consumer protections, and (13) Whether the rate mechanism is understandable and acceptable to consumers. The statement specifically authorizes electric distribution utilities to propose critical peak pricing or similar demand-based programs using average usage over critical peak periods. These types of programs are to include a fixed charge that reflects metering, final line transformer, and service drop costs, a critical peak volumetric or average demand component that reflects usage over distribution system components during localized peak usage periods, and a volumetric on-peak, off-peak or other type of rate for other costs. Comments on the policy statement were filed in October 2018.	
RI	Demand Response	In October 2018, National Grid filed its 2019 System Reliability Procurement Report. In the report, the utility proposed a Customer-Facing Program Enhancement Study to develop and test new customer engagement approaches for demand response.	Docket No. 4889 2019 System Reliability Procurement Report
	Grid Modernization	In March 2017, the Governor of Rhode Island directed the Public Utilities Commission, Office of Energy Resources, and Division of Public Utilities and Carriers to design a new regulatory framework for Rhode Island's electric system. Work sessions on utility business models, grid connectivity and functionality, distribution system planning, and beneficial electrification were held during 2017. In November 2017, the group presented its Phase One Report to the Governor. The report identifies several goals, including: (1) utilizing pay-for-performance utility models, (2) investing in intelligence and connectivity, (3) identifying new sources of utility revenue, (4) leveraging information, (5) increasing reliability and resilience. The plan presents a series of recommendations for achieving these goals and may serve as a guiding document for Rhode Island's future energy transformation. In November 2017, National Grid proposed a portfolio of grid modernization investments ("Power System Transformation") as part of its effort to implement work done in the Power Sector Transformation investigation process. A settlement agreement was filed in June 2018, which includes a Power Sector Transformation (PST) advisory group to review progress on delivery of all PST components of the three-year rate plan (grid modernization, AMF, time-varying rates, electric transportation, electric heat, energy storage, and performance incentive mechanisms). The group	Power Sector Transformation Initiative Phase One Report Docket No. 4780 Docket No. 4770 Amended Settlement Agreement

		includes a subcommittee on strategic electrification, as well as a subcommittee on AMF and grid modernization. The settlement also calls for National Grid to work with the advisory group to develop a comprehensive grid modernization plan. The Commission approved an amended version of the settlement agreement. The AMF and Grid Modernization Plan subcommittee met in October, November, and December 2018. Members supported extending the filing deadline for the updated AMF business case to early June 2019. The Electric Transportation subcommittee met in October 2018, and the Energy Storage subcommittee met in November 2018.	
VA	AMI, Data Access	H.B. 2332 requires the commission to convene a data access stakeholder group by September 1, 2019. The stakeholder group is to review and consider a number of issues related to AMI data access, including customer privacy; the impact of data sharing on the physical and cybersecurity of utility infrastructure; aggregating anonymized data; user-friendly formats for data access; opt-in/opt-out conditions for access to customers' utility usage data by the electric utility, a contracted agent, and a third party; and the costs of and cost recovery mechanisms for changes to electric utility infrastructure needed to implement regulations. The stakeholder group must complete its work no later than April 1, 2020 and report its recommendations to the General Assembly. The Governor signed the bill into law in March 2019.	H.B. 2332 (E)
	Energy Storage	The FY 2019 budget bill, enacted in June 2018, allocated funds to the Department of Mines, Minerals and Energy to commission a study and provide recommendations for advancing energy storage in Virginia. Specifically, the report will include a comprehensive and quantitative benefit-cost analysis of energy storage in Virginia, including an analysis of the benefits of various levels of energy storage adoption across the generation, transmission, and distribution systems. The study will also explore the federal and state regulatory barriers and incentives for energy storage, the economic benefits of storage that are unique to Virginia, and current best practices concerning safety. The study is to be completed by September 15, 2019. Stratagen Consulting was selected to complete the study.	H.B. 5002 (2018) Press Release
	Rate Reform	H.B. 2547, in addition to making several changes related to solar, requires Dominion to convene a stakeholder group to provide recommendations related to the implementation of advanced	H.B. 2547 (E)

		metering technology and TOU rates. The Governor signed the bill into law in March 2019.	
VT	Grid Modernization, Utility Business Model	In June 2017, the Vermont Public Utility Commission opened an investigation into utility regulation in the state, following a request from the Department of Public Service. Specifically, the Commission is reexamining Vermont's regulatory structure in response to recent transformations in technology, state policy, and other areas. The proceeding is divided into four topic areas: (1) principles of rate regulation, (2) rate design, (3) grid impacts, and (4) municipal and cooperative utility issues. Two workshops were held in August and September 2017. The first workshop focused on the scope and framework for the proceeding, while the second workshop focused on non-traditional forms of regulation used outside of Vermont and variations in the way traditional regulation is used in other jurisdictions. A third workshop was held in early October 2017, addressing the merits and disadvantages of traditional and alternative forms of regulation. In December 2017, the Department of Public Service filed its recommendations on future alternative regulation plans. The Department identified five goals for alternative regulation: (1) maintain affordability and spur economic development, (2) offer accessibility and transparency, (3) align utility and customer interests, (4) accommodate different types of utilities, and (5) include appropriate timeframes for review. The Department also recommended that the PUC issue an order refining the requirements for alternative regulation, based on statutory criteria. The Department's recommendations outline the statutory requirements for alternative regulation, as well as other plan features that may be considered, including decoupling, multi-year rate plans, performance incentive mechanisms and metrics, a fuel or power adjustment clause, exogenous adjustments, earnings sharing, and new businesses and third-party access. The Commission issued an order in July 2018, providing principles and considerations for future alternative regulation plans. These principles and considerations include advancement of state energy policy, open participation and transparency, fair balance of risks and rewards, just and reasonable rates, and service quality.	Docket No. 17-3142-PET Media Release

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

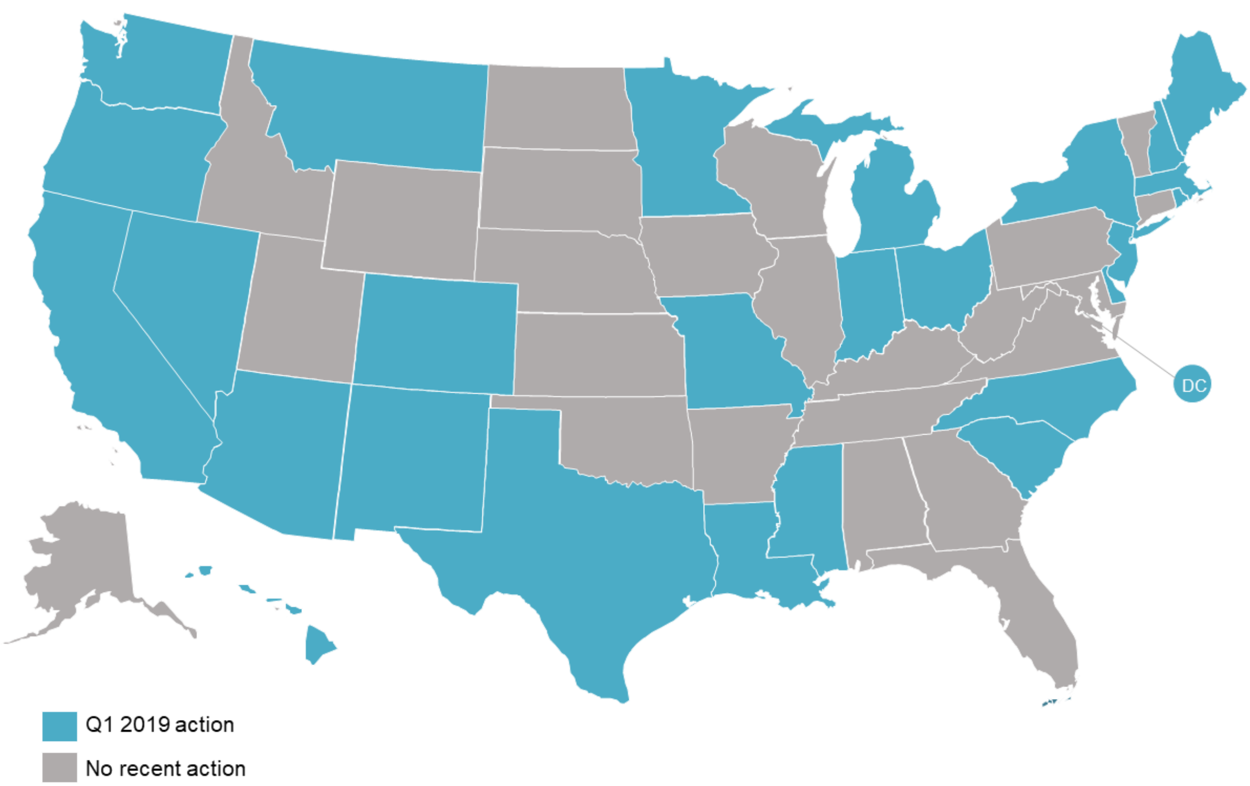
PLANNING AND MARKET ACCESS

Key Takeaways:

- In Q1 2019, 26 states plus DC considered changes to utility planning processes and market access rules.
- Six ISOs/RTOs have compliance filings pending before the Federal Energy Regulatory Commission to comply with Order 841, which requires wholesale market operators to revise market rules in order to allow full participation by energy storage resources.
- The Oregon Public Utility Commission opened a proceeding on distribution system planning, and the Colorado Public Utilities Commission opened a rulemaking related to electric resource planning.

As the potential roles for energy storage and other distributed energy resources within our energy system grow more important, policymakers and regulators are working to revise both wholesale market rules and planning methods to ensure these resources are appropriately considered in utility planning.

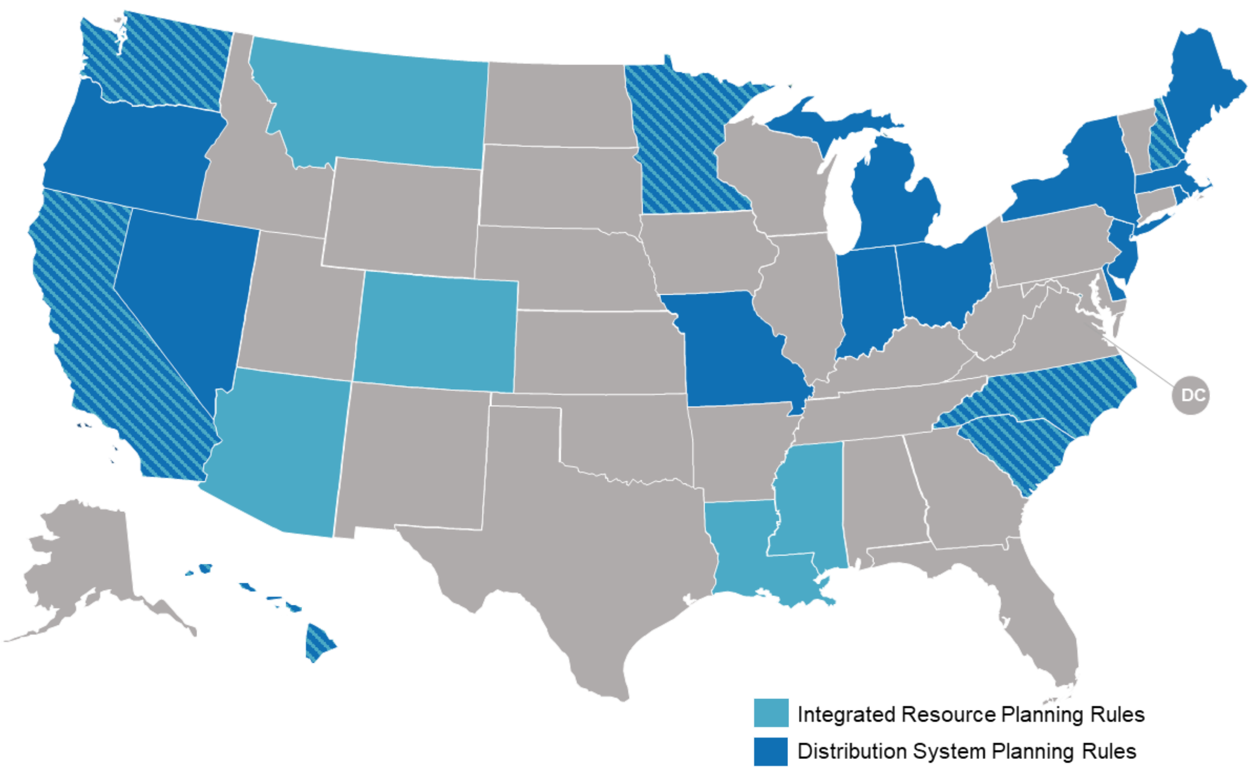
Figure 10. State Action on Planning and Market Access (Q1 2019)



In Q1 2019, 26 states and DC considered revisions to planning processes or market access rules related to grid modernization. Distribution system planning was the second most commonly addressed issue overall, following energy storage deployment. Several states are working to establish or revise distribution system planning rules in order to increase transparency of the distribution planning process, analyze and prioritize distribution system investments, and identify the locational value of distributed energy resources (DERs). The Oregon Public Utility Commission opened a new proceeding on distribution system planning during the quarter.

Some states are even considering more holistic planning processes that integrate generation, transmission, distribution, and DER planning. For example, the New Hampshire Public Utility Commission Staff recommended an integrated distribution planning process, which combines distribution system and grid modernization planning with the current least-cost integrated resource planning process.

Figure 11. State Action on Utility Planning Processes (Q1 2019)



A number of states are also considering changes to their integrated resource planning processes. In Montana, the state legislature passed a bill creating a more defined process for integrated resource planning and requiring greater consideration of demand-side management. Several bills pending in Minnesota require consideration of energy storage options in integrated resource planning, while proposed rules in Colorado would require an assessment of ancillary services and consideration of potential emissions reductions.

Table 3. Updates on Planning and Market Access (Q1 2019)

State/RTO	Sub-Topic	Description	Source
AZ	Integrated Resource Planning	In August 2016, Arizona Corporation Commission Chairman Little opened a docket to review, modernize, and expand Arizona's Renewable Energy Standard and Tariff. In late January 2018, Commissioner Tobin filed his proposed Energy Modernization Plan. The proposed plan includes amending the state's integrated resource planning rules to support and promote the other policies within the proposed Energy Modernization Plan, including an energy storage target and clean peak target. In February 2018, the Commission Staff issued a Notice of Inquiry, soliciting comments on many specific questions related to Commissioner Tobin's proposal. In early July 2018, Commissioner Tobin filed a formal set of draft rules implementing his proposed Energy Modernization Plan. Later in July, several Commissioners expressed support for opening a new rulemaking docket to consider changes to the state's Renewable Energy Standard and Commissioner Tobin's Energy Modernization Plan. In August 2018, the Commission opened a rulemaking docket to evaluate modification to several different energy rules (see Docket No. RU-00000A-18-0284).	Docket No. E-00000Q-16-0289 Proposed Energy Modernization Plan Notice of Inquiry Draft Rules
	Integrated Resource Planning	In May 2018, the Arizona Corporation Commission opened a docket to modify the state's resource planning and procurement rules. In February 2019, the Commission Staff filed a memo proposing that a workshop be held in April 2019 to begin reviewing resource planning and procurement rules, as well as energy efficiency standard rules, baseload security, the biennial transmission assessment, and technological developments in the generation and delivery of energy.	Docket No. RE-00000A-18-0137
	Integrated Resource Planning	In August 2018, the Arizona Corporation Commission (ACC) opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules. Rules to be addressed in the proceeding include the renewable energy standard, energy efficiency standards, resource planning and procurement, retail electric competition, net metering, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. In February 2019, the ACC Staff filed a memo proposing that a workshop be held in April 2019 to review resource planning and procurement rules.	Docket No. RU-00000A-18-0284

CA	Distribution System Planning	California has an ongoing proceeding examining Distribution Resource Plans and the value of DERs to the distribution system. The proceeding was divided into three tracks, with Track 2 involving a range of demonstration projects to examine various location and technology scenarios, some of which include storage. In a February 2017 decision, the California Public Utilities Commission (CPUC) granted approval to some Track 2 demonstration projects, rejected others, and approved only some elements of other projects. The utilities filed revisions to their proposed projects, which the CPUC approved in June 2017. Track 3 is subdivided into 3 sub-tracks, with Sub-Track 2 concerning grid modernization investments. The CPUC issued a decision in March 2018 regarding Sub-Track 2. Specifically, the decision defines grid modernization, establishes a classification framework to serve as a common vocabulary for grid modernization investments, establishes the structure and timing of the grid modernization planning process, and provides guidance on how the CPUC will evaluate the cost-effectiveness of grid modernization investments. The decision also requires the utilities to submit Grid Modernization Plans in their general rate cases. In December 2018, the ALJ issued a ruling rejecting confidentiality claims that would have subjected some distribution system planning data to non-disclosure agreements. A February 2019 ruling seeks comments on possible changes and improvements to the 2019 cycle of the Distribution Investment Deferral Framework.	Docket No. R-14-08-013
	Distribution System Planning, Non-Wires Alternatives	California has an ongoing proceeding to investigate methods for integrating DERs. The scope of the proceeding includes: (1) the development of a competitive solicitation framework for DERs, (2) the continued development of technology-neutral cost-effectiveness methods and protocols, (3) leveraging the work performed in the Distribution Resource Plans (DRP) proceeding (Docket No. R-14-08-013) and (4) the role of the utilities, business models, and financial interests with respect to DER deployment. A December 2016 decision established a Competitive Solicitation Framework and a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for investments in traditional distribution infrastructure. A scoping memo filed in February 2018 added two additional issues to the proceeding: (1) alternative sourcing mechanisms or approaches that satisfy distribution planning objectives and (2) the ways in which existing programs, incentives, and tariffs can be coordinated to maximize the locational benefits and minimize the	Docket No. R-14-10-003 Proposed Decision

	costs of DERs. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report on its Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism pilot. The report indicates that SDG&E launched its Pilot Request for Offers in January 2018 and did not receive any conforming bids that were cost-effective. The report presents a series of recommendations for improving the process, and the Commission opened a comment period on the report. The Commission issued a ruling in January 2019 directing parties to respond to questions regarding the development of a stakeholder process for updating the Avoided Cost Calculator. A proposed decision filed in March 2019 adopts new cost-effectiveness analysis framework policies for DERs. The proposed decision states that the Total Resource Cost (TRC) test will be the primary test of cost-effectiveness for all DERs beginning on July 1, 2019 that require cost-effectiveness analyses. The proposed decision additionally clarifies that the modified TRC, Program Administrator Cost (PAC), and Ratepayer Impact Measure (RIM) tests will be used as replacements for the existing tests. Lastly, the proposed decision establishes that the three-element Societal Cost Test (SCT) is to be tested through December 31, 2020 for planning purposes in the integrated resource planning proceeding. The three elements of the SCT are a societal discount rate, an avoided social cost of carbon, and an air quality adder value.	
Integrated Resource Planning	A.B. 1584 requires the Commission to develop and use methodologies for allocating electrical system integration resource procurement obligations, and any associated costs resulting from a failure to satisfy an allocated procurement obligation, to each load-serving entity based on the contribution of that entity's resource portfolio to the electric system conditions that created the need for the system integration resource procurement.	A.B. 1584 (I)
Integrated Resource Planning	S.B. 155 requires the Commission to add a requirement to the integrated resource planning process to ensure at least 65% of the procurement that a retail seller counts toward the renewable portfolio standard requirement of each compliance period be from contracts of 10 years or more in duration or from its ownership or ownership agreements from eligible renewable energy resources.	S.B. 155 (I)
Resilience Planning	In October 2018, the California Public Utilities Commission opened a rulemaking proceeding related to S.B. 901 (enacted in 2018) regarding electric utility	Docket No. R-18-10-007

		wildfire mitigation plans, which may include grid modernization investments. A prehearing conference was held in November 2018, and the Commission established a schedule for the proceeding in early December 2018. In January 2019, an ALJ issued an order providing the template for the utilities to submit their mitigation plans, and the utilities filed their plans in February 2019. A ruling issued later in the month requested additional information on the utilities' wildfire mitigation plans, which the utilities later provided. Evidentiary hearings began in March 2019.	
CA / CAISO	Wholesale Market Rules	The California Public Utilities Commission (CPUC) is working to integrate demand response into the California ISO market, and is investigating whether a competitive procurement mechanism for supply-side resources outside of traditional utility programs is viable. An initial pilot auction was conducted in 2015 with delivery in 2016, and a second auction took place in 2016 with delivery in 2017. The CPUC later approved a third pilot auction in 2017. OhmConnect filed a request for evaluation of the pilot programs to be expedited so the demand response auction mechanism could be made permanent by Summer 2018. In April 2017, the CPUC issued a decision denying OhmConnect's request and the request of the joint demand response parties. An October 2017 decision approved a 2018 auction for 2019 deliveries. The decision also established two working groups, a Supply Side Working Group and a Load Shift Working Group. A petition for modification was filed in January 2018, asking the CPUC to modify an October 2016 decision that adopted guidance for future demand response portfolios. Specifically, the petition asks the CPUC to clarify that the decision's resource prohibition does not apply to energy storage and suspend any requirements for energy storage used for demand response to meet the Self-Generation Incentive Program's (SGIP) greenhouse gas emissions standard. A June 2018 order grants in part the petition for modification, clarifying that energy storage not coupled with fossil fuel-fired generation is exempt from the list of prohibited resources. In doing so, the CPUC removed the requirement that storage had to meet the SGIP's greenhouse gas standard. The order closed the proceeding. In July 2018, Southern California Edison filed a petition for modification on behalf of all workshop participants. The petition seeks to modify a November 2017 decision, to clarify the implementation steps for the Competitive Neutrality Cost Causation Principle. The proceeding has been re-opened.	Docket No. R-13-09-011

CAISO	Non-Wires Alternatives, Wholesale Market Rules	California ISO (CAISO) launched a new initiative in March 2018 concerning energy storage as a transmission asset. CAISO plans to use the initiative to examine methods for enabling storage providing cost-based transmission services to also participate in ISO markets and receive market revenues to provide ratepayer benefits. CAISO received a number of comments after releasing an issue paper in March 2018, and held a web conference before releasing its straw proposal in May 2018. CAISO received numerous comments on the straw proposal and followed up with stakeholder meetings in May and June. The straw proposal provides two cost recovery mechanisms: full cost-of-service based cost recovery and energy market crediting, and partial cost-of-service based cost recovery and no energy market crediting. CAISO released a revised straw proposal in August 2018 and a second revised straw proposal in October 2018. A conference was held in January 2019.	SATA Initiative Website Second Revised Straw Proposal
	Wholesale Market Rules	California ISO's (CAISO) Energy Storage and Distributed Energy Phase 2 initiative is examining ways to enhance the ability of ISO-connected and distribution-connected resources to participate in the ISO market. Among the resources considered in this initiative are energy storage, plug-in electric vehicles, and demand response. Phase 2 of the initiative explored alternative baselines, distinguishing between charging energy and station power, and a net benefits test for demand response resources. Phase 3 was launched in September 2017 with the release of an issue paper outlining some of the concepts for discussions. A straw proposal was released in February 2018. The straw proposal refined the scope of Phase 3 and included an initial set of solutions. The scope of Phase 3 includes new bidding and real-time dispatch options for demand response, the removal of the single load-serving entity aggregation requirement, the development of a load shift product, and the recognition of sub-metered electric vehicle supply equipment curtailment. A working group meeting was held in March 2018 to discuss the straw proposal, and a draft final proposal was released in July 2018. The CAISO Board of Governors approved the proposal in September 2018. Phase 4 launched in February 2019 with a web conference. Phase 4 is considering refinements to the DER and storage participation models. It will also examine expanding the models to optimally capture the value of these resources, and use resource design attributes to support grid reliability and allow for multiple-use applications. A meeting was held in March 2019.	ESDER Initiative Website Issue Paper Straw Proposal Draft Final Proposal

	Wholesale Market Rules	In December 2018, California ISO (CAISO) submitted a tariff filing to FERC in order to comply with Order 841. The tariff adds energy storage to the definition of participating resources and allows storage resources with 100 kW or more of capacity to participate in CAISO markets (the minimum capacity for other resources is 500 kW). The tariff also exempts storage resources from access charges for withdrawing energy from the CAISO grid. Parties filed comments during Q1 2019.	FERC Docket No. ER19-468
CO	Integrated Resource Planning	On February 27, 2019, the Colorado Public Utilities Commission opened a rulemaking docket with proposed changes to electric resource planning (ERP), renewable energy standard, net metering, community solar, PURPA, and interconnection rules. This follows last year's stakeholder proceeding (Docket No. 17M-0694E) on these issues. The changes to electric resource planning rules include requiring an assessment of potentially cost-effective early retirements and use of best-value employment metrics. The rules would also require an assessment of ancillary services, including load following, reactive power - voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services. In the assessment of need for resources, utility would be required to consider the benefits of potential emission reductions. Parties filed their initial comments in March 2019. Xcel Energy generally supported the proposed rule changes, but expressed concern that the rules might limit the ability of utilities to acquire new resources outside of the ERP process. Solar industry and environmental parties argued in favor of including evaluations of existing resources in the ERP process.	Docket No. 19R-0096E
DC	Non-Wires Alternatives	In June 2015, the DC Public Service Commission (PSC) initiated a proceeding to identify technologies and policies that can modernize its energy delivery system for increased sustainability, reliability, efficiency, cost-effectiveness, and interactivity. In January 2017, the Staff presented its Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) report. In October 2017, the PSC accepted the Staff's proposed MEDSIS report. In February 2018, the PSC adopted a MEDSIS vision statement and stated that it would conduct a request for proposals for a MEDSIS consultant. The Commission selected the Smart Electric Power Alliance (SEPA) in June 2018 to serve as the consultant. SEPA led the MEDSIS technical conference in which stakeholders were able to provide input on whether a	Formal Case No. 1130 MEDSIS website MEDSIS Staff Report Order No. 19432 (August 2018) Order No. 19692 (September 2018)

		system assessment was needed and what working groups should be formed in Phase 2 of the MEDSIS Initiative. SEPA filed its recommendations, which the Commission approved in an August 2018 decision. Specifically, SEPA recommended against a full system assessment at this time, and recommended the formation of six working groups, including a working group on non-wires alternatives. A later decision, filed in September 2018 tasked the non-wires alternatives working group with proposing a definition for "smart inverter" and considering utility ownership of DERs like energy storage devices, and submit its recommendations for the Commission's consideration. In December 2018 and January 2019, the proceeding continued with stakeholders filing comments. The Commission will host a two-day joint working group meeting in late April 2019 to facilitate stakeholder and public input on the draft MEDSIS working group recommendations, released in mid-April 2019.	
DE	Distribution System Planning	In April 2018, Delmarva Power, the Public Advocate, and the Public Service Commission Staff signed a memorandum of understanding agreeing to work together to develop a proposal on enhanced distribution system planning. In early July 2018, the Commission opened a docket to develop distribution system planning rules for electric, natural gas, and water utilities. The first meeting was held in July 2018, and joint recommendations from Delmarva, the Public Advocate and Commission Staff are due by September 1, 2019.	Docket No. 18-0935
FERC (All ISOs & RTOs)	Wholesale Market Rules	In January 2018, FERC opened a docket on grid resilience and requested that the ISOs and RTOS submit responses regarding the development of a common understanding of resilience, how the ISOs/RTOs assess threats to resilience, and how the ISOs/RTOs mitigate threats to resilience. The PJM Interconnection filed comments in March 2018, arguing that FERC should require the various market operators to make changes to their tariffs in order to price resilience attributes; the remaining five regional grid operators filed comments arguing against such a change. While many of the issues focused on by commenters pertain to the resilience aspects of different electricity generation sources (i.e. nuclear, coal, gas, renewables), some commenters have discussed the resilience aspects of grid modernizing technologies, such as energy storage, improved grid communications, and transmission/distribution automation. No action took place in this docket during Q1 2019.	FERC Docket No. AD18-7

HI	Distribution System Planning, Integrated Resource Planning, Non-Wires Alternatives	The HECO companies filed their Integrated Grid Planning Report with the Public Utilities Commission in March 2018. The report proposes the merger of three separate planning processes – generation, transmission, and distribution – with the goal of identifying system-wide needs, coordinating solutions, and developing an optimized portfolio of assets. The report also proposes a stakeholder process to develop the planning process, starting with the formation of a working group to assist in the development of the forecasts and input assumptions that will drive the planning process. The stakeholder process will continue with the identification of the resource, transmission, and distribution needs, and the methods through which these needs will be met. The Commission opened a new proceeding in July 2018 to examine the Grid Planning Report. In December 2018, the HECO companies submitted their Integrated Grid Planning Workplan, which describes the process the utilities would go through in developing their integrated grid plans and the methods of stakeholder engagement. The Commission accepted the Integrated Grid Planning Workplan in March 2019.	Docket No. 2018-0165 Integrated Grid Planning Report Integrated Grid Planning Workplan
IN	Distribution System Planning	H.B. 1470 requires that a utility's transmission, distribution, and storage system improvement plan covers a period of at least five years and not more than nine years, and be updated annually. The bill also makes advanced technology investments eligible to be recovered through transmission, distribution, and storage system investment charges. The bill passed the House in February 2019 and the Senate in March 2019.	H.B. 1470 (P2)
ISO-NE	Wholesale Market Rules	In October 2018, ISO-New England (ISO-NE) filed proposed revisions to its Transmission, Markets, and Services Tariff to allow energy storage technologies to more fully participate in the ISO-NE markets. The revised rules allow storage facilities capable of rapidly (10 minutes or less) and continuously (able to be dispatched to any level between maximum consumption capability and maximum generation capability) transitioning between consumption and generation to avoid the commitment process. The revisions also create a platform to allow for the provision of regulation services. The revisions will help the ISO comply with FERC Order 841, but will not include all of the new elements required for compliance with the order. FERC accepted the revisions to Market Rule 1, and they became effective on April 1, 2019. ISO-NE's full Order 841 compliance plan remains pending before FERC.	FERC Docket No. ER19-470 ISO-NE Filing

LA	Integrated Resource Planning	As part of the Public Service Commission Staff's proposed modified net metering rules, filed in November 2017, utilities would be required to incorporate DG into their integrated resource plans. Specifically, utilities would be required to document the current level of DG in their service territories, discuss and analyze the impact that DG is having on the system resource requirements, and forecast future DG for at least a five-year period. Utilities would be encouraged to provide analysis or documentation on the monetary value of the avoided energy and capacity benefits provided by DG historically and forecasted into the future. In January 2019, the Commission Staff filed its final proposed DG rules, which make only relatively minor changes to the draft previous version of the proposed rules.	Docket No. R-33929 Final Proposed DG Rules (Part 1) Final Proposed DG Rules (Part 2)
MA	Distribution System Planning	H. 2808 and S. 1932 require IOUs to file grid modernization plans every three years. The plans are to include the locational benefits of energy resources located on the distribution system and the optimal locations for distribution resources over the next 10 years. These locational benefits are to be based on generation capacity needs, avoided or increased transmission and distribution investments, safety and reliability benefits, and any other benefits the resources can provide. The utilities are to create publicly accessible hosting capacity maps and propose location-based incentives for local energy resources. The plans are also to propose AMI deployment to be completed by 2026. Additionally, the bills create a Grid Modernization Consumer Board that is to review and approve utility grid modernization plans.	H. 2808 (I) S. 1932 (I)
	Distribution System Planning	S. 2008 requires distribution companies and municipal lighting plants to make a map available each year that shows areas of critical need for energy storage systems.	S. 2008 (I)
	Distribution System Planning, Non-Wires Alternatives	S. 2007 requires IOUs to file grid modernization plans every five years. The plans are to include the locational benefits of energy resources located on the distribution system and the optimal locations for distribution resources over the next 10 years. These locational benefits are to be based on generation capacity needs, avoided or increased transmission and distribution investments, safety and reliability benefits, and any other benefits the resources can provide. The utilities are to create publicly accessible hosting capacity maps and propose location-based incentives for local energy resources. The bill also creates a Grid Modernization Consumer Board that is to review and approve utility grid modernization plans. Additionally, the bill requires a determination of wires	S. 2007 (I)

		before beginning construction of a new transmission or distribution line.	
	Microgrid Rules	H. 2849 and S. 1940 allow municipalities, state agencies, and private customers to establish microgrids by providing an exception to utility rights to exclusive service or franchise for microgrids designed for energy generation or resiliency	H. 2849 (I) S. 1940 (I)
	Microgrid Rules	H. 2914 allows municipalities, state agencies, and private customers to establish microgrids by providing an exception to utility rights to exclusive service or franchise.	H. 2914 (I)
ME	Distribution System Planning, Non-Wires Alternatives	L.D. 1181 establishes a non-wires alternative coordinator as a position within the Office of the Public Advocate. The coordinator would be tasked with investigating non-wires alternatives to proposed transmission and distribution projects, reviewing and analyzing distributing system planning studies, identifying non-wires alternatives to proposed utility capital investments, and implementing procurement plans for non-wires alternatives. The coordinator is to collaborate with utilities, Efficiency Maine, and other interested parties. The bill also directs utilities to file distribution system planning studies each year. Note that in a recent regulatory proceeding, the Public Utilities Commission designated the state's utilities as the non-transmission alternatives coordinator.	L.D. 1181 (I)
	Microgrid Rules	L.D. 13 defines microgrids and specifies that a person constructing, maintaining, or operating a new microgrid approved by the Public Utilities Commission is not a public utility and subject to public utility regulation. The bill establishes requirements for new microgrids to be approved by the Commission, including the microgrids must not service a total load of more than 10 MW, the person proposing the project must have the financial and technical capacity to operate the microgrid, there is a relationship between the microgrid operator and the consumers in the area to be served by the microgrid, the person proposing the microgrid is not an investor-owned utility or affiliate, and the microgrid won't negatively affect the reliability and security of the grid. The bill also states that microgrids will be subject to Commission oversight to ensure reliability and security of the grid and regarding consumer protection for microgrid consumers.	L.D. 13 (I)
	Non-Wires Alternatives	In April 2016, the Public Utilities Commission (PUC) opened an investigation into the designation of a Non-Transmission Alternative (NTA) Coordinator, and a final order was published in December 2017. The Commission found that the state's distribution utilities,	Docket No. 2018-00171 Docket No. 2016-00049

Central Maine Power and Emera Maine, have the best knowledge of the system, as well as the technical and engineering knowledge necessary to perform the role of the NTA Coordinator. However, the PUC noted that incentives in existing ratemaking encourage the utilities to invest in wires solutions over non-wires alternatives. Therefore, the PUC directed the utilities to file proposals to address this incentive so that wires and non-wires solutions are on an equal footing from a ratemaking perspective. In June 2018, the utilities filed their NTA report, which recommends (1) the establishment of a revenue decoupling mechanism for Emera, (2) the establishment of ratemaking approaches that treat situations expenditures related to non-wires alternatives (NWA) similar to traditional transmission and distribution investments, (3) incentives for the utilities to plan for and deploy NWA, (4) the establishment of a process to review utility NWA plans similar to utility transmission projects, (5) ratemaking tools for timely recovery of NWA costs, and (6) an approach to address innovative and cost-effective grid modernization projects, including pilots and demonstration projects, to develop ways of increasing efficiency and supporting future NWA projects. An initial case conference was held in July 2018, and the utilities filed a supplemental NTA report in early October 2018.

The PUC Staff filed a bench memorandum with its proposed ratemaking and process alternatives in December 2018. The Staff recommended that for Emera, a revenue decoupling mechanism be considered as part of a more comprehensive rate review and that different ratemaking approaches be taken for transmission-level NWAs and distribution-level NWAs. For transmission NWAs, costs would be recovered through an annual rate adjustment and investments/capitalized expenses could earn a return at the utility's FERC-authorized rate of return. Any costs not allowed in FERC-jurisdictional transmission rates could be recovered through the distribution rate adjustment. For distribution NWAs, costs would also be recovered through an annual rate adjustment, with the utility earning a return at the rate of return on rate base approved by the PUC. Transmission NWA costs would be allocated to all utility customers, while distribution NWA costs would be allocated only to customers taking service at distribution voltages. For third-party owned NWAs, expenses would be capitalized through a service agreement, lease, or contract, and any expenses not capitalized could be recovered in the distribution rate adjustment. The Staff proposed that any ratemaking incentive program be structured as a pilot program. The Staff also

	proposed that the utilities provide additional detail on the internal processes for considering NWAs and that the utilities file annual reports that detail capacity and load by circuit and identify all growth-related investments for the next three years. The Office of the Public Advocate also filed recommendations in December 2018, recommending that the Commission reject the utilities' proposal, that the utilities file a complete financial model with earnings and ratepayer savings under different shared savings mechanisms, that a shared savings mechanism with 30% savings retained by utilities be approved, that capitalization of NWA expenses be approved, that utilities only be allowed to recover NWA incentives once capacity benchmarks are reached, and only allow recovery of capitalized NWA assets beginning at the time of the next rate case, but allow recovery of NWA expenses on a current basis. The utilities filed supplemental information on NWA screening in late March 2019, and the PUC denied the Office of the Public Advocate's (OPA) request for a stay. The OPA had requested a stay because the state legislature is currently considering a bill related to non-wires alternatives.	
Non-Wires Alternatives	In August 2018, the Office of the Public Advocate (OPA) filed a petition requesting that the Commission amend its "safe harbor" rules for local transmission planning. Under current rules, stakeholders are not permitted to bring forward evidence or cost-benefit studies to demonstrate why different planning assumptions should be used. The OPA suggests that allowing this intervention will help in the selection of reliability solutions that best suit customer needs. Comments were filed in September, October, and November 2018. The hearing examiner filed a report in January 2019, recommending that the Commission reopen its transmission planning rules to examine whether certain practices should be changed. Central Maine Power filed a response in February 2019, recommending that the Commission reject the hearing examiner's recommendations and maintain the current safe harbor provisions. Emera's response indicates that the utility is not opposed to a "well-defined process to reexamine specific standards. The OPA also filed a response in February 2019, agreeing with the examiner's report, but disagreeing that there is no due process violation inherent in the transmission planning order. The OPA recommends reopening the transmission planning rules to consider changes to the safe harbor provisions, but also to provide for intervenor challenges to overly conservative safe harbor provisions. In early April 2019, the Commission issued an order reopening a 2013 order establishing certain transmission planning	Docket No. 2011-00494

		procedures in order to examine whether some of these practices should be modified.	
MI	Distribution System Planning, Non-Wires Alternatives	In April 2018, the Michigan Public Service Commission (PSC) opened this docket for DTE Electric Company and Consumers Energy Company to file their five-year distribution investment and maintenance plans. Both utilities submitted their plans in April 2018, after which comments on the plans were accepted. A technical conference was held in August 2018 to discuss stakeholder concerns with the plans. In September 2018, the PSC Staff filed a report providing a framework for future distribution plans. The report contained several recommendations, including that the PSC require a dynamic approach to load forecasting, that utilities be required to provide publicly available hosting capacity information, that utilities using AMI use standards developed by the Green Button Alliance to provide customers access to usage data, that future plans provide criteria for and information on non-wires alternatives projects, and that a common cost-benefit methodology be developed for use in future distribution plans. In November 2018, the PSC issued an order requiring the utilities to file their next round of distribution plans by mid-2020. The PSC order does not implement all of the Staff report's recommendations; the order does not require a dynamic approach to load forecasting, does not require hosting capacity studies to be performed, and does not require use of Green Button. The order does call for a technical conference to develop a common cost-benefit methodology and for a discussion of criteria for non-wires alternatives analyses. Environmental parties filed joint comments on Indiana Michigan Power's distribution plan on December 21, 2018. Indiana Michigan Power filed the final version of its distribution plan on April 3, 2019. The plan includes grid modernization investments, including AMI deployment, distribution system automation, and other smart grid technologies totaling $56 million over 5 years; around $25 million of that investment is for AMI deployment, which will be finished by the end of 2020.	Docket No. U-20147 Michigan Distribution Planning Framework
MISO	Wholesale Market Rules	In April 2017, DTE Electric submitted an Issue Submission Form to MISO requesting that tariffs for energy storage be updated. Current rules treat storage as a synchronous generator and do not recognize that storage acts as both a generator and a load, which results in sub-optimal use of the storage resource. This request references an ongoing review of this issue by FERC prompted by an Indianapolis Power & Light request in 2016. MISO held Common Issue Meetings on energy storage in July and August 2017. At the August meeting, instructions were given	Energy Storage Resource Optimization Energy Storage Task Force Page Common Issue Meeting July 24

		to various MISO subcommittees to investigate storage integration issues. In December 2017, MISO released a charter for an Energy Storage Task Force, which met throughout 2018 to discuss issues surrounding the integration of energy storage. A revised charter was issued in September 2018, which indicates the group will convene until June 2019. Meetings were held in January, February, and April 2019.	Common Issue Meeting August 24
	Wholesale Market Rules	In response to FERC Order 841, issued in February 2018, the MISO Advisory Committee is holding proceedings on incorporating energy storage into wholesale markets. MISO held a joint stakeholder meeting in October 2018 to present its plans to comply with Order 841. In December 2018, MISO filed tariffs with FERC in order to comply with Order 841. MISO is adopting a definition of "electric storage resource" based on the language of Order 841. Additionally, MISO filed tariff changes which will allow energy storage resources to participate in capacity, resource adequacy, energy and ancillary services, blackstart service, and reactive supply and voltage control markets; energy storage had previously been limited to energy and operating reserves markets in MISO. MISO will phase out its transitional SER-Type II participation model for energy storage in March 2020, after the new participation model comes into effect. Parties filed comments on the proposed tariffs throughout Q1 2019. In early April 2019, FERC filed a request for additional information on the compliance filing. FERC requested clarification on several aspects of MISO's tariff and how it satisfies the requirements of Order 841, including asking MISO to clarify whether storage resources that are not located within MISO but that are connected to its grid could participate in MISO markets.	FERC Docket No. ER19-465 MISO Issue Tracker Order 841 Joint Meeting October 10, 2018
MN	Distribution System Planning	The Public Utilities Commission (PUC) opened a docket in May 2015 to consider the development of policies related to grid modernization. The proceeding features broad stakeholder engagement and numerous workshops. In April 2017, the PUC issued a request for comments from Xcel Energy, Minnesota Power, and Otter Tail Power (cooperative and municipal utilities were encouraged but not required to respond) related to the following questions: (A) How do Minnesota utilities currently plan their distribution systems? (B) What is the status of each utility's current plan? and (C) Are there ways to improve or augment utility planning processes? Parties provided comments on these questions during 2017. In April 2018, the Commission Staff released a briefing paper, setting forth a proposed procedure and schedule for	Docket No. 15-556

	developing utility-specific integrated distribution plans. According to the Staff's schedule, Xcel Energy and the Dakota Electric Association would have until November 1, 2018 to submit their integrated distribution plans, and Otter Tail and Minnesota Power would have until November 1, 2019. The PUC held a meeting in April 2018 to discuss the actions the PUC should take on distribution system planning for each of the utilities. An August 2018 order affirmed the IDP filing requirement for Xcel, and Xcel filed its IDP in November 2018 in Docket No. 18-251. The Commission opened a comment period for Xcel's IDP on November 19, 2018. No significant action took place in Q1 2019.	
Distribution System Planning	The Public Utilities Commission opened a new proceeding in April 2018 for the development of Xcel Energy's 2018 Integrated Distribution Plan (IDP). The Commission Staff created draft filing requirements for the IDP, which were discussed in an April 2018 meeting. The proposed requirements direct utilities to file plans addressing: (1) long-term distribution system modifications and investments, (2) considerations used in related planning processes, and (3) long-term distribution system future outlooks. The Commission issued an order in August 2018 approving the IDP filing requirements. Xcel must file its IDP with the Commission annually beginning November 1, 2018. Xcel filed its IDP in November 2018, and the Commission opened a comment period.	Docket No. 18-251 Order
Distribution System Planning	The Commission opened a new proceeding in April 2018 for the development of Otter Tail Power's 2018 Integrated Distribution Plan (IDP). The public staff created draft filing requirements for the IDP, which were discussed in an April 2018 meeting. The proposed requirements direct utilities to file plans addressing: long-term distribution system modifications and investments, considerations used in related planning processes, and long-term distribution system future outlooks. The Commission opened a formal comment period in June 2018. In July the Commission granted a request for an extension on the deadlines for comments and reply comments to the end of September 2018. A February 2019 order formally adopted the filing requirements for Otter Tail and set a deadline of November 1, 2019 for Otter Tail to file its IDP.	Docket No. 18-253
Distribution System Planning	The Commission opened a new proceeding in April 2018 for the development of Minnesota Power's 2018 Integrated Distribution Plan (IDP). The public staff created draft filing requirements for the IDP, which were discussed in an April 2018 meeting. The proposed requirements direct utilities to file plans	Docket No. 18-254

	addressing: long-term distribution system modifications and investments, considerations used in related planning processes, and long-term distribution system future outlooks. The Commission opened a formal comment period in June 2018. In July the Commission granted a request for an extension on the deadlines for comments and reply comments to the end of September 2018. A February 2019 order formally adopted the filing requirements for Minnesota Power and set a deadline of November 1, 2019 for Minnesota Power to file its IDP.	
Distribution System Planning	Xcel Energy filed its hosting capacity report in November 2018, as required by the Commission. The Commission stated that the hosting capacity report must be detailed enough to provide developers with a reliable estimate of the available level of hosting capacity per feeder. The report must also be detailed enough to inform future distribution system planning efforts and upgrades necessary to facilitate the continued efficient integration of distributed generation. Comments on the report were accepted through February 2019.	Docket No. 18-684
Integrated Resource Planning	H.B. 165 and S.B. 100 add requirements for energy storage to be considered in integrated resource planning.	H.B. 165 (I) S.B. 100 (P1)
Integrated Resource Planning	H.B. 1165 and S.B. 1608 add requirements for energy storage to be considered in integrated resource planning.	H.B. 1165 (I) S.B. 1608 (I)
Integrated Resource Planning	H.B. 1405 and S.B. 1456 make certain changes to the integrated resource planning process, including a stated preference for clean energy resources, a term which includes energy storage.	H.B. 1405 (I) S.B. 1456 (I)
Integrated Resource Planning	H.B. 1833 and S.B. 2067 make changes to the integrated resource planning process by requiring utilities to include a least cost plan for meeting 50%, 75% and 100% of all energy needs from both new and refurbished generating facilities through a combination of clean energy and carbon-free resources. The bills also require resource plans to include an assessment of energy storage systems that analyzes how the deployment of energy storage systems contributes to meeting identified generation and capacity needs and evaluating ancillary services.	H.B. 1833 (I) S.B. 2067 (I)
Integrated Resource Planning	H.B. 1956 and S.B. 2451 make certain changes to the integrated resource planning process, including a stated preference for clean energy resources, a term which includes energy storage. The bill also establishes a carbon-free standard, which requires	H.B. 1956 (I) S.B. 2451 (I)

		100% of the electricity in Minnesota to be carbon-free by 2050.	
MO	Distribution System Planning	In March 2017, the Missouri Public Service Commission (PSC) staff requested that the Commission open a workshop docket to gather information related the PSC's role in shaping the solar landscape. The proceeding is also intended to examine issues surrounding modified rate design proposals, AMI, property assessed clean energy financing, and the electric vehicle market. As part of the proceeding, the PSC Staff released a report on DERs in early April 2018. The report does not specifically recommend that a value of solar study be conducted, but did find that studies conducted in other states may not be fully informative for Missouri. Rather than recommending a full value study, Staff recommended that stakeholders focus on incorporating DERs into distribution system planning, as this may help provide a framework for DER valuation. In May 2018, PSC Staff published a draft rule for comment, and in late May 2018 a workshop was held to discuss the draft rule. In late June 2018, the PSC Staff filed an updated version of the draft rule for comment. The current version of the draft rule requires utilities to maintain a database of current DERs on their grids, assess the market potential for DERs as part of their triennial compliance filings, and evaluate DERs as part of the resource planning process, including integration with the transmission and distribution system. Several parties filed comments on the draft rule in July 2018. The Office of the Public Counsel argued against the need for the new rules, stating that current rules are sufficient and arguing that the database would be created too late to help inform current policy deliberations. The Division of Energy from the Missouri Department of Economic Development and Renew Missouri generally supported the draft rules, and made suggestions to include additional elements in the required analyses. The comments jointly submitted by utility parties suggested using a different definition for cost-effectiveness (the draft rules use a definition from the National Efficiency Screening Project, while the utilities suggest using the definition from the Missouri Energy Efficiency Investment Act of 2009) and suggest providing information on current DERs on the grid through annual filings rather than an online database.	Docket No. EW-2017-0245 June 2018 Draft Rule
MS	Integrated Resource Planning	In May 2018, the Public Service Commission opened a proceeding to consider the development of IRP rules. Parties filed initial comments in August 2018. In December 2018, the Commission issued a request for comments on Entergy Mississippi's proposed IRP	Docket No. 2018-AD-64

		rule, which it submitted with its initial comments. The proposed rules would require the consideration of utility-owned or controlled DERs and enabling technologies, such as broadband access, and data. The rules reference energy storage in the Demand Response and Energy Efficiency section. Several parties filed comments on the proposed rules in February 2019. The Attorney General's comments note that the IRP process should give equal consideration and access to third party-owned energy resources, in addition to traditional utilities. The Sierra Club's comments include many critiques, including that there is a lack of detail regarding battery storage options, the cost data used by Entergy is outdated, and some value streams of storage are not captured in current IRP modeling. The Sierra Club provided several recommendations related to battery storage, including that the important co-benefits of battery storage should be incorporated into the analysis, that additional battery storage alternatives (such as a two-hour option) should be considered, that the modeling should allow for solar or wind coupled with batteries, and that the model should capture the energy shifting value of storage or demand response. The Southern Alliance for Clean Energy's comments are also critical of the proposed rules. Mississippi Power proposed a revision that would allow utilities to develop on-bill financing options for demand-side management and DERs. Mississippi Power also proposed an addition that would permit utilities to make up to $35 million each year in Enhanced Grid Investments to improve reliability, promote economic development, and improve customer access to modern service. Entergy proposed additions to the rule as well, including language allowing utilities to remove vegetation management and grid resiliency costs from base rates and recover them through an alternative cost recovery mechanism.	
MT	Integrated Resource Planning	H.B. 597 establishes additional requirements for integrated resource planning. The bill requires the Public Service Commission (PSC) to adopt IRP rules and utilities to file plans every three years (currently the PSC may adopt rules, but is not required to, and there is no set schedule for IRP filing). The plans must include demand-side management programs and at least two alternate scenarios that use increasing amounts of renewable energy and demand-side management. The bill also requires the Commission to provide for public comment on the plan and authorizes the Commission to identify deficiencies in the plan.	H.B. 597 (P2)
NC	Distribution System	In a general rate case filed in August 2017, Duke Energy Carolinas requested cost recovery for certain	E-7 Sub 1146

	Planning, Integrated Resource Planning	grid investments as part of its Power/Forward Carolinas plan. A final order approved many elements of the general rate case, but left open many issues related Power/Forward. A technical workshop regarding Duke Energy's revised grid investment plan (Grid Improvement Plan) was held in November 2018. In January 2019, Duke filed a report summarizing the November 2018 workshop on its Grid Improvement Plan, detailing stakeholder feedback. Part of the Grid Improvement Plan involves Integrated System Operations Planning (ISOP), which covers generation, transmission, and distribution. An additional stakeholder workshop is scheduled for May 2019.	
NH	Distribution System Planning, Integrated Resource Planning	In February 2019, the Public Utilities Commission Staff filed its final grid modernization report and recommendations. The Staff recommend that utilities be required to submit integrated distribution plans (IDPs), including both grid modernization initiatives and their least cost integrated resource plans. The Staff identified objectives, capabilities, and functionalities for utilities to base their assessments of their distribution systems on. The functionalities include forecasting DER and demand growth, long-term system planning, scenario-based planning, DER locational value analysis, interconnection process, distribution system information sharing, integrated resource transmission and distribution planning, sensing and measurement, control, communications, asset management, integrated operational engineering and system operations, distribution system model, T-D interface coordination, real time DER operation, Volt/VAR and power quality management, fault management, cybersecurity, physical security, settlement procedures, DER portfolio management, DER sourcing (non-wires alternatives), market information sharing, and market oversight. The IDPs are to include a 10-year roadmap for meeting grid objectives and a 5-year implementation plan (capital investment/operational expense plan). The IDP is to include sections on common cost-effectiveness/business case assumptions, current system capabilities and processes, distribution system planning, architectural strategies and considerations, distribution operations, advanced meter functionality, rate design, cybersecurity and privacy, performance metrics, and rates and regulatory. A technical session for discussion and questions on the report was held in March 3029, and written comments were accepted in April 2019. A public comment hearing was also held in April.	Docket No. IR 15-296 Final Report (February 2019)

	Non-Wires Alternatives	As part of the New Hampshire Public Utilities Commission's (PUC) June 2017 net metering successor tariff decision, the PUC ordered the implementation of four pilot programs, including a non-wires alternatives (NWA) pilot. The pilot would be focused on the installation of DG in lieu of distribution system upgrades. In April 2018, the PUC issued an order addressing the NWA pilot program, suspending the development of any DG-only NWA programs and deferring consideration of unrestricted NWA implementation to a grid modernization or integrated resource planning context. Instead, the PUC ordered that a distribution-level locational DG value study be undertaken instead. In late November 2018, the Commission Staff filed a report with a proposed scope and timeline for the distribution-level locational DG valuation study. The proposed study scope covers only technologies eligible for net metering and will examine the value of avoided or deferred distribution investment costs resulting from elimination of capacity constraints. The study is expected to begin in Q2 2019 and be completed by the end of 2019. In February 2019, the Commission approved the locational value of DG study scope. The PUC is encouraging the Commission Staff to work with the consultant to develop and, if possible, make available a flexible and accessible valuation model so that net metering technologies other than solar may also be considered. The Office of the Consumer Advocate (OCA) filed a motion for clarification in early March 2019, related to discovery on load growth projections, capital investment plans, and distribution system planning methodologies, as well as the Commission's decision declining to require a counterfactual baseline. In March 2019, the PUC granted the OCA's motion for clarification, specifying that parties will have the opportunity to serve discovery on the utilities regarding load growth projections, capital investment plans, other distribution system planning methodologies, and marginal cost of service studies.	Docket No. DE 16-576 Order No. 26,029 Order No. 26,124
NJ	Distribution System Planning, Non-Wires Alternatives	A.B. 4525, introduced in 2018, directs the Board of Public Utilities to develop rules for the procurement of energy storage systems as part of the transmission and distribution planning process.	A.B. 4525 (I)
NM	Competitive Procurement	S.B. 456 requires IOUs to issue a request for competitive proposals any time they intend to request approval to procure a new energy resource, including to receive a certificate of public convenience and necessity to include a resource in the utility's rate base. The bill requires an independent evaluator to be	S.B. 456 (D)

		used and modeling inputs and assumptions to be shared with bidders. Energy storage projects would be subject to these requirements. The bill did not advance during the 2019 legislative session.	
NV	Distribution System Planning	S.B. 146, enacted in June 2017, requires NV Energy to submit a Distributed Resources Plan to the Public Utilities Commission of Nevada (PUCN) by April 1, 2019 as an addendum to its integrated resource plan. The plan must (1) evaluate the locational benefits and costs of DERs, (2) propose standard tariffs for the deployment of cost-effective DERs, (3) propose cost-effective methods of coordinating existing programs to maximize the locational benefits of DERs, (4) identify additional spending necessary to integrate distributed resources into distribution planning, and (5) identify barriers to the deployment of DERs. The PUCN opened an investigation and rulemaking docket in July 2017 to implement S.B. 146. The PUCN released draft temporary regulations in July 2018, which it later approved through an October 2018 order. The temporary regulations establish the filing, content, approval, and updating process for Distributed Resources Plans. NV Energy filed its Distributed Resource Plan in a new docket (Docket No. 19-04003) on April 1, 2019.	Docket No. 19-04003 Distributed Resources Plan Docket No. 17-08022 Temporary Regulations S.B. 146 (2017)
NY	Distribution System Planning	A.B. 3804 makes it the policy of the state to encourage, and, where appropriate, mandate the use of smart grid systems by electric utilities. The bill establishes that utilities can recover reasonable costs for smart grid planning, building, and operation, and require all utilities with more than 10,000 service connections to develop and adopt a smart grid system deployment plan by June 30, 2020.	A.B. 3804 (I)
	Distribution System Planning	This docket contains filings related to the Distribution System Implementation Plans (DSIP) that New York utilities are required to submit as part of the Reforming the Energy Vision process. Utilities filed their initial DSIPs in 2016, and updated DSIPs are required to be filed every two years, with the next updates being due by June 30, 2018. In April 2018, the Public Service Commission issued a guidance document laying out guidelines for submission of updated DSIPs. Several utilities requested an extension of the filing deadline to July 31, 2018, and the request was granted by the PSC. In July 2018, all utilities filed their updated DSIPs. In mid-April 2019, the Utility Intervention Unit of the Division of Consumer Protection at the New York Department of State filed comments on the DSIP process, encouraging the PSC to update its benefit-cost analysis framework to require utilities to include dynamic analysis in their benefit-costs analyses.	Docket No. 16-01444

	Distribution System Planning, Non-Wires Alternatives	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the Public Service Commission (PSC) adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. As part of the roadmap, the PSC directed the utilities to compile an inventory of unused, suitable land for non-wires alternatives, as well as interconnection upgrade costs for non-wires alternatives that can be included in RFPs. The Commission also directed the utilities to work with NYSERDA to develop a pilot DER data platform including anonymized customer and system data for DER developers. In February 2019, the PSC announced the formation of a working group on market design and integration, with a meeting held on March 5, 2019. A conference of the working group was held later in March 2019.	Docket No. 18-00516/18-E-0130 NYSERDA Website
NYISO	Wholesale Market Rules	In December 2018, New York ISO (NYISO) filed revisions to its tariffs and market rules to facilitate participation of energy storage resources, in compliance with FERC Order 841. Order 841 directed ISOs and RTOs to revise their rules to allow energy storage resources to participate in wholesale energy, capacity, and ancillary markets. NYISO offers four modes for energy storage: (1) ISO Committed Fixed (2) ISO Committed Flexible, (3) Self Committed Fixed, and (4) Self Committed Flexible. Under ISO Committed, the ISO would determine optimal dispatch time. Under ISO Committed Flexible, the storage system would be dispatched in the real time market based on LMP. Under the Self Committed options, the suppliers would decide the time for dispatch. Energy storage systems are required to continuously supply energy for four hours in NYISO. NYISO tariffs apply only to wholesale resources; behind-the-meter resources must be sub-metered and dual participation in utility programs and NYISO markets is not allowed. FERC allowed a 21-day comment period on the revised proposed rules. Several stakeholders requested that FERC to extend the comment period to 45 days, as the proposal includes a significant amount of filings to review. The final rules are required to be implemented by December 3, 2019 to comply with Order 841. NYISO has requested an implementation extension to May 1, 2020 as it is currently updating its market software.	FERC Docket No. ER19-467
OH	Distribution System	The Public Utilities Commission of Ohio (PUCO) opened three new dockets in October 2018 to build	Docket No. 18-1596-EL-GRD

	Planning, Non-Wires Alternatives	upon the PowerForward investigation. The Distribution System Planning Workgroup docket is identifying issues that currently exist or may arise in the integrated distribution planning process. The Workgroup may develop recommendations to the Commission on the following: future scenarios for customer DER adoption in Ohio, and how these scenarios should be incorporated into utility forecasting and planning processes; modifications to interconnection standards, including defining required functions and settings for advanced inverters; development of non-wires alternatives suitability criteria, processes, and a timeline for implementing non-wires alternatives opportunities; evaluation of options for procuring non-wires alternatives; defining hosting capacity analyses (HCA) use cases; identifying an appropriate HCA methodology and associated tools and data requirements to satisfy use cases; a timeline for initial HCA analysis and publication of results for each utility; and development of portals for sharing information on peak load forecasts, capital plans, hosting capacity maps, heat maps reflecting locational value and other key data. Further, the Commission encourages the Workgroup to determine a process for identifying where it would be beneficial to deploy energy storage solutions. As a first step in November 2018, the Attorney Examiner proposed that each utility conduct a current-state assessment of their respective distribution system's present capability to integrate and accommodate the broad array of initiatives which are likely to occur. The goal of the current-state assessment is to identify areas of strength and weakness, highlighting those areas in which the distribution system is lacking the necessary infrastructure to assure the provision of adequate and reliable service in a more decentralized environment characterized by a proliferation of DERs, as well as how much visibility the utilities have into their own distribution systems. Additionally, the current-state assessment should include an evaluation of a utility's current system characteristics, an overview of the distribution planning process and projects resulting from the planning process, as well as the software tools used for planning. The utilities filed the current state assessments in early April 2019. The Distribution System Planning Workgroup had additional meetings in March and April 2019.	
OR	Distribution System Planning	The Commission Staff issued a whitepaper in February 2019 titled "A Proposal for Electric Distribution System Planning" and held a stakeholder workshop to review it. Based on the interest it received, in March 2019, the Commission Staff	Docket No. UM 2005

		recommended that the Commission open an investigation into distribution system planning to develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments. The Commission adopted the Staff's recommendation at its March 21, 2019 public meeting.	
PJM	Wholesale Market Rules	In April 2017, the Energy Storage Association (ESA) filed a complaint against PJM before FERC, alleging that PJM unilaterally changed its frequency regulation market, discriminating against existing energy storage resources. The PJM frequency regulation market is categorized into RegA (for traditional resources with limited ramp rates) and RegD (for resources with short ramp rates, including batteries). Previously, the RegD resources were energy neutral. However, in January 2017, PJM changed its rules that maintained energy neutrality and eliminated the provision for RegD resource use for short durations. FERC issued a decision in March 2018, partially granting ESA's requests, ruling that parameters for PJM's regulation market signals must be included in the PJM tariff and are subject to FERC review. The decision also instructs FERC staff to set up a technical conference on other issues arising from this matter. In May 2018, the parties requested and FERC approved appointment of a settlement judge and postponement of the technical conference. Settlement conferences took place throughout the third continued into 2019; the ALJ presiding over the case indicated that the parties have reached an agreement in principle. A settlement agreement for this matter was filed in Docket ER19-1651 on April 23, 2019.	FERC Docket No. EL17-64 FERC Complaint
	Wholesale Market Rules	In December 2018, PJM filed its compliance plan to update its tariffs and market rules to facilitate the participation of energy storage resources in its markets, in compliance with FERC Order 841. Order 841 directed ISOs and RTOs to revise their market rules to integrate energy storage into wholesale energy, capacity, and ancillary markets. Energy storage systems are required to continuously supply energy for ten hours in PJM. PJM categorizes energy storage into three modes: (1) continuous, (2) charge, and (3) discharge. In continuous mode, resource can both charge or discharge with no limitation on start up or ramp rate. PJM would require all storage resources not owned by utilities only to sell back to PJM, and not sell to others or use stored power themselves. FERC allowed a 21-day comment period on the revised rules. Several stakeholders requested that FERC to extend the comment period to 45 days, as the proposal includes a significant amount of filings to review. In early April 2019, FERC filed a request for	FERC Docket No. ER19-469

		information regarding PJM's tariff filing. As PJM's proposed tariff relies on existing tariffs in many cases, rather than developing new storage-specific tariffs, FERC requested clarification on how PJM's rules will allow storage to participate in accordance with the requirements of Order 841. The final rules are required to be implemented by December 3, 2019 to comply with Order 841.	
RI	Distribution System Planning, Non-Wires Alternatives	In October 2018, National Grid filed its 2019 System Reliability Procurement (SRP) Report. National Grid proposed efforts to develop and promote the Rhode Island System Data Portal. The Portal includes company reports on distribution system planning, an overview of distribution assets, a heat map of distribution feeder load, and a hosting capacity map. As part of the SRP report, National Grid proposed (1) identifying locations where electric vehicle fast charging stations could be installed by September 2019, (2) identifying areas where large non-electric public transportation fleets are located to forecast potential fleet conversion to electric vehicles by July 2019, and (3) including redacted area studies by the end of 2019. The SRP report also includes a proposal to reissue an RFP for a non-wires alternative (NWA) opportunity in Tiverton and Little Compton. A battery storage project was previously selected for this NWA opportunity, but the project was not able to be completed. The report identifies additional NWA opportunities and proposes that RFPs be issued for these as well. A hearing was held in December 2018.	Docket No. 4889 2019 System Reliability Procurement Report
SC	Distribution System Planning, Integrated Resource Planning	In Duke Energy Progress' and Duke Energy Carolinas' general rate cases, filed in November 2018, the utilities requested approval for their Grid Improvement Plan. The plan is broken into three categories: (1) compliance-driven programs to protect the grid, (2) programs using advanced technologies to modernize the grid, and (3) projects and programs to optimize the customer's experience. The plan also includes developing an Integrated System Operations Planning (ISOP) process that will integrate generation, transmission, distribution, and customer program planning, as well as a data access program that will integrate customer data with Green Button. The plan also includes physical security and cybersecurity investments, including fencing, lighting, intrusion detection technology, replacing Windows-based relays with devices to operate in a Linux environment, firewalls, replacement of vulnerable devices, and EMP protection. Additionally, the plan includes electric transportation programs that have been proposed by the utility in a separate proceeding. The three-year total budget for the plan is about $455 million for the two utilities. The Office of Regulatory	Docket No. 2018-318-E Docket No. 2018-319-E

		Staff filed a motion to consider the Grid Improvement Plan in its own new proceeding, then later filed a stipulation with Duke Energy for the same request.	
	Integrated Resource Planning	Among other changes, H.B. 3659 and S.B. 332 revise the state's integrated resource planning requirements. Under the revised rules, utilities would be required to provide a summary of planned electric transmission investments and develop several resource portfolios to evaluate the range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's obligations. The evaluation would need to consider different levels of renewable energy and cogeneration, energy efficiency, and demand response. The plan is also to include a forecast of the utility's peak demand and actions the utility proposes to reduce this peak. The House passed an amended version of H.B. 3659 in February 2019.	H.B. 3659 (P1) S.B. 332 (I)
	Integrated Resource Planning	Existing law requires the state's utilities to file integrated resource plans with the State Energy Office, which does not have regulatory authority over the utilities. S.B. 620 requires the IOUs to file integrated resource plans with the Public Service Commission every three years, and the Commission will open a proceeding to consider the plan. Electric cooperatives and municipal utilities must file integrated resource plans with the State Energy Office. The bill provides additional criteria for integrated resource plans.	S.B. 620 (I)
SPP	Wholesale Market Rules	In December 2018, the Southwest Power Pool filed its FERC Order 841 compliance plan. The plan would allow storage resources to register as a "market storage resource" and provide energy, regulation-up, regulation-down, spinning reserve, and supplemental reserve services.	FERC Docket No. ER19-460
TX	Non-Wires Alternatives	In February 2018, the Texas Public Utility Commission (PUC) opened this docket to address the use of non-traditional technologies for electric delivery service. This proceeding arises from a previous docket (No. 46368), which concerned AEP Texas North Company's request to deploy energy storage as a non-wires alternative. The earlier docket has been closed to allow for this wider investigation. In early October 2018, the PUC issued a request for comments on a set of questions pertaining to non-traditional electric delivery technologies. The questions address several issues, including whether and how transmission and distribution utilities could use non-traditional technologies (including energy storage) to improve reliability on their systems; whether there is legal authority for them to do so;	Docket No. 48023 Docket No. 46368

		what steps regulators should take to approve, track, and manage these non-traditional technologies; and what effects these non-traditional technologies could have on the ERCOT market. In January 2019, the PUC Staff delivered a memo summarizing the comments received and requesting that the matter be discussed at the January open meeting.	
	Resource Planning	In September 2018, the Public Utility Commission (PUC) opened a docket to amend a rule (16 TAC 25.505) dealing with resource adequacy in the ERCOT region. The rule currently prescribes several measures, including reporting requirements for utilities, publications on resource adequacy to be prepared by ERCOT, and a scarcity pricing mechanism. In December 2018, the PUC proposed several changes to the rule. The proposed changes include a change to the gas price index, changes to the scarcity pricing mechanism, and updated reporting requirements. The PUC approved the rule proposal at its December 20, 2018 meeting and proposed publication of the amendments on January 3, 2019. Parties filed comments on the proposal for publication throughout February 2019.	Docket No. 48721 16 TAC 25.505
WA	Distribution System Planning	In May 2015, the Washington Utilities and Transportation Commission staff initiated a proceeding (UE-151069) to investigate the role of energy storage in utility planning and procurement. The Commission later initiated a rulemaking proceeding in September 2016 (U-161024) to consider changes to the integrated resource planning (IRP) process. The two proceedings overlap in certain areas. The Commission specifically seeks to evaluate how recent advances in the energy industry, such as the growth of DG and development of energy storage technologies, should be treated in the IRP. In October 2017, the Commission issued its final Report and Policy Statement on Treatment of Energy Storage Technologies in IRP and Resource Acquisition. The report cites energy storage as a key enabling technology for utilities to comply with state energy policies, and that utilities should be diligently working to identify and pursue cost-effective energy storage opportunities. The report specifically discusses three policy principles related to energy storage: (1) changing planning paradigms, (2) providing modeling guidelines, and (3) identifying principles for regulatory treatment of energy storage investments. In January 2018, the Commission submitted its Report on Current Practices in Distributed Energy Resource Planning. The report includes a survey of how other states conduct DER planning, a survey of the current practices of Washington utilities, and 10 recommendations for improving the planning process.	Docket No. UE-151069 Docket No. U-161024 Final Policy Statement Final Report Distribution Planning Draft Rules

	In April 2018, the Commission filed draft rules for distributed system planning in Docket No. U-161024. The draft rules require utilities to form a separate advisory group to assist the utilities in developing their distribution system plans, in addition to the usual IRP advisory group. According to the draft rules, distribution system plans must include a short term plan identifying planned capital investments, a long term plan identifying how the utility is improving distribution system operations and transparency, and a report identifying potential tools and practices to facilitate the integration of DERs. A number of parties filed comments on the draft rules during Q2 and Q3 2018, and a workshop was held in October 2018. In December 2018, the Commission released draft rules for utility RFPs. The draft rules include language promoting the use of technology-neutral RFPs and requiring RFPs to identify utility-owned transmission assets that are available to be used by bidders to assist in meeting the resource need. The rules also require the use of an independent evaluator under certain conditions, such as when the utility or an affiliate is allowed to submit a bid.	
Distribution System Planning, Non-Wires Alternatives	H.B. 1126 establishes objectives for DER planning processes, including identifying the gaps impeding a robust planning process and upgrades that would allow the utility to quantify the locational and temporal value of distribution system resources; proposing monitoring, control, and metering upgrades; identifying potential programs and tariffs to fairly compensate customers for the value of their DERs; forecasting the growth of DERs on the system; providing a 10-year plan for distribution system investments and an analysis of non-wires alternatives for major transmission and distribution investments; including the DERs identified in the integrated resource planning process; including a high level cybersecurity and data privacy discussion; and discussing lessons learned in the planning cycle. The bill also requires utilities to procure DERs through a price-based, technology-neutral process. The House passed the bill in March 2019 and the Senate passed it in April 2019.	H.B. 1126 (P2)

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

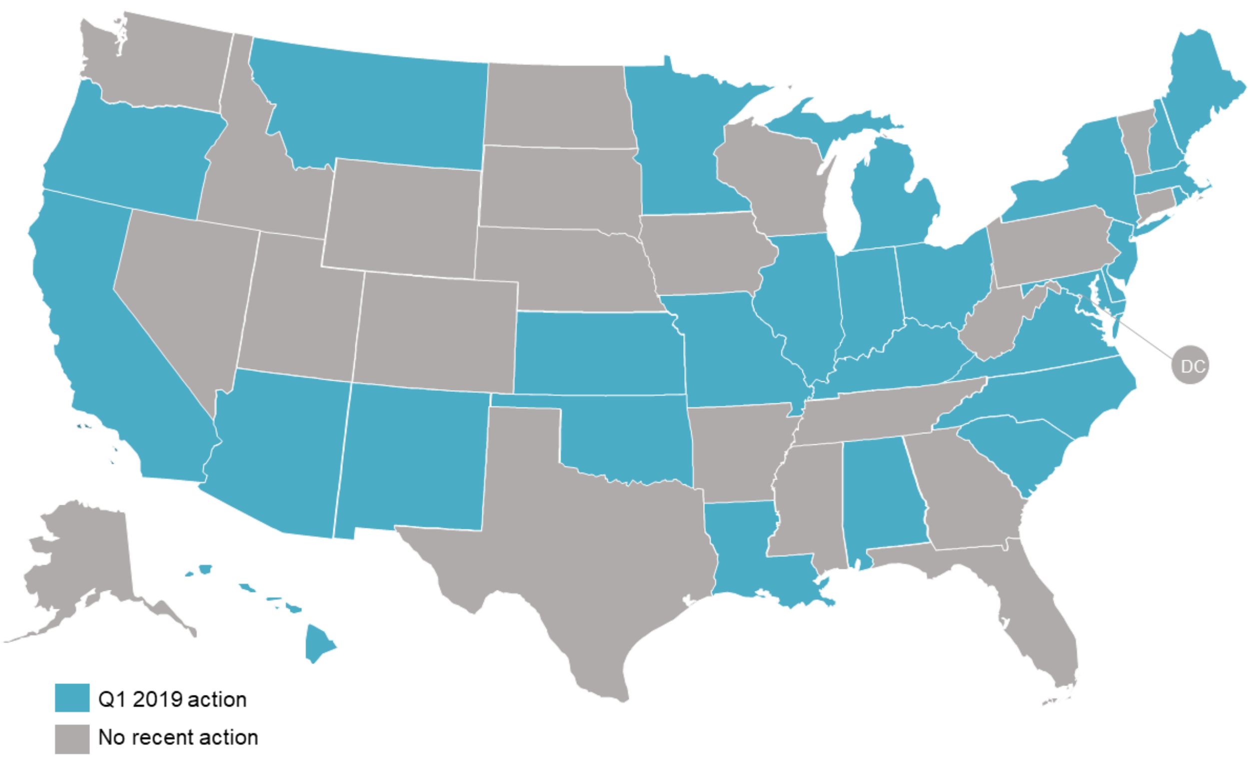
UTILITY BUSINESS MODEL AND RATE REFORMS

Key Takeaways:

- In Q1 2019, 28 states took actions to reform rate designs, regulatory structures, or utility business models.
- Eighteen states took action on rate design reforms, while 19 states considered utility business model or ratemaking reforms.
- The Hawaii Public Utilities Commission Staff filed its performance-based regulation recommendations.

In Q1 2019, 28 states took actions related to utility business model and rate reforms. Of these, 18 states considered rate design changes, while 19 states considered utility business model or ratemaking adjustments. The most common types of reforms considered were related to time-varying rates and performance-based regulation.

Figure 12. Action on Utility Business Model and Rate Reform (Q1 2019)

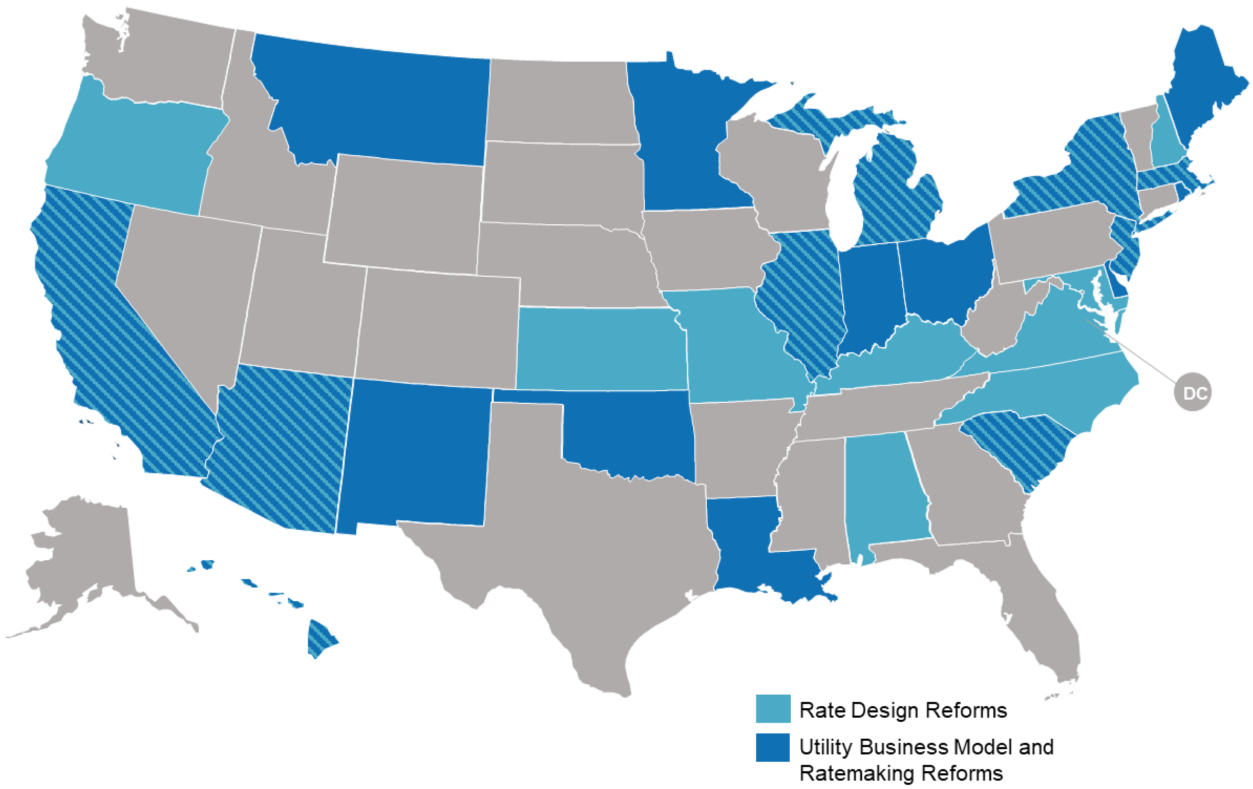


Several states and utilities took actions related to time-varying rates and other advanced rate designs, such as dynamic pricing and critical peak pricing, during Q1 2019. Legislation enacted in Virginia requires Dominion Energy to file time-varying rate schedules by March 2020, and Hawaii regulators directed the Hawaiian Electric Company utilities to file an advanced rate design strategy to realize more of the benefits of advanced metering infrastructure. A proposed decision filed in DTE Electric's rate case would approve default residential time-varying rates in

Michigan, while Unitil filed its proposed time-of-use rate study. Duke Energy filed its proposed dynamic pricing pilots in North Carolina in early April 2019.

Performance-based regulation remains one of the most common types of utility business model reforms. The Hawaii Public Utilities Commission Staff filed its performance-based regulation recommendations in February 2019. The Staff recommended the adoption of new incentive mechanisms based on interconnection experience, customer engagement, and distributed energy resource asset effectiveness. Public Service Company of Oklahoma had proposed new performance incentives as part of a general rate case, but these were not included in a settlement agreement approved in March 2019.

Figure 13. Action on Rate Design and Utility Business Models (Q1 2019)



Other types of utility business model reforms under consideration include decoupling and retail competition. Emera Maine proposed a new decoupling mechanism as part of its general rate case filed in March 2019. However, the utility withdrew the rate case in April. Legislation enacted in New Mexico during the quarter authorizes the Public Regulation Commission to approve rate adjustment mechanisms to remove regulatory disincentives. In Montana, legislators considered a bill that would have transitioned the state toward retail competition; however, this bill did not advance before the legislative session ended.

Table 4. Updates on Utility Business Model and Rate Reform (Q1 2019)

State	Sub-Topic	Description	Source
AL	Critical Peak Pricing	In January 2019, Alabama Power filed proposed revisions to its critical peak pricing rider, which is available to certain residential customers. The program currently provides a thermostat to participants that allows the utility to remotely manage the customer's HVAC system during critical peak periods. The utility notes that this technology has now become obsolete and it has not identified a reasonable substitute, so the utility is redesigning the program. Under the revised program Alabama Power would notify participants of critical peak periods through text message or email, and customers would be responsible for adjusting their energy use. The rider includes a critical peak rate of 33.1158 cents per kWh and 15.6158 cents per kWh for the months from June through September. The Commission issued an order in early February 2019, approving the revised rider.	Docket No. U-4732
AZ	Multi-Technology Rates	As part of a recommended order in Tucson Electric Power's DG rate design proceeding, the ALJ directed the utility to propose a new tariff similar to the R-TECH tariff recently approved for Arizona Public Service. The R-TECH tariff is only available to customers with at least two eligible behind-the-meter technologies, such as solar PV, battery storage, or an electric vehicle. The recommended order allows the utility to include a demand ratchet in this tariff only if an option without a demand ratchet is also proposed. The Commission issued a final decision in September 2018, adopting the ALJ's recommendation for the utility to propose a tariff similar to Arizona Public Service's R-TECH rate. In January 2019, TEP filed its R-TECH tariff in compliance with the Commission's decision. The tariff will be available to up to 4,000 customers. The tariff features two demand charges (on-peak and off-peak), on-peak and off-peak energy and power supply charges.	Docket No. E-01933A-15-0322 TEP R-TECH Tariff Filing
	Multi-Technology Rates	As part of a recommended order in UNS Electric's DG rate design proceeding, the ALJ directed the utility to propose a new tariff similar to the R-TECH tariff recently approved for Arizona Public Service. The R-TECH tariff is only available to customers with at least two eligible behind-the-meter technologies, such as solar PV, battery storage, or an electric vehicle. The recommended order allows the utility to include a demand ratchet in this tariff only if an option without a demand ratchet is also proposed. The Commission issued a final decision in September 2018, adopting the ALJ's recommendation for the utility to propose a tariff similar to Arizona Public Service's R-TECH rate.	Docket No. E-04204A-15-0142 UNS R-TECH Tariff Filing

		In January 2019, UNS filed its R-TECH tariff in compliance with the Commission's decision. The tariff will be available to up to 1,000 customers. The tariff features two demand charges (on-peak and off-peak), on-peak and off-peak energy and power supply charges.	
	Utility Business Model Reform	In December 2018, the Arizona Corporation Commission opened a docket to address modifications to retail electric competition rules. Questions related to retail electric competition were included in the November 28, 2018 special open meeting notice. In January 2019, Arizonans for Electric Choice and Competition filed its initial comments, responding to the Commission's list of questions. The Commission Staff filed a memo in February 2019, proposing that a workshop be held in July 2019 to address retail electric competition rules.	Docket No. RE-00000A-18-0405
CA	Demand Charges, Time-Varying Rates	In November 2018, the California Solar and Storage Association, California Energy Storage Association, Enel X, ENGIE Services, ENGIE Storage, OhmConnect, Solar Energy Industries Association, and Stem filed a petition for the California Public Utilities Commission (CPUC) to open a rulemaking to (1) consider whether to require the state's three large IOUs to offer real-time pricing tariffs to all customer classes whether the utilities should be required to offer less complex dynamic rates for the residential and small commercial classes and (2) consider two demand charge reforms for non-residential customers. Specifically, the groups are requesting that the CPUC prohibit non-coincident peak demand charges and consider alternatives to a single monthly coincident peak demand measurement, such as daily coincident peak demand charges or charges based on averaged demand. A decision filed in March 2019 denied the petition, stating that these issues should instead be considered in normal rate design proceedings for the individual utilities.	Docket No. P-18-11-004
	Time-Varying Rates	Pacific Gas and Electric (PG&E) filed its proposed TOU rates in December 2017. PG&E's proposal includes a default TOU rate with a 3-hour peak period, and three optional rates for customers who opt out of the default. The proposal also includes a limited roll-out set for November 1, 2019, but PG&E states that it would prefer a roll-out of October 1, 2020 to allow more time for marketing and other transitional actions. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve	Docket No. A-17-12-011 December 2018 Decision

	questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 decision established that PG&E will begin transitioning eligible customers to default TOU rates in October 2020. The California Solar and Storage Association filed a motion in June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. In December 2018, the Commission issued a decision which largely adopted the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers. An evidentiary hearing took place in January 2019. An email ruling filed in March 2019 sought additional information from PG&E.	
Time-Varying Rates	San Diego Gas and Electric (SDG&E) filed its proposed TOU rates in December 2017. SDG&E's proposal includes a default 3-period tiered TOU rate. Customers who wish to opt out of the default rate can choose between a simpler 2-period TOU rate or a tiered non-TOU rate. SDG&E's proposal includes a transition to default TOU rates on January 1, 2019. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 decision established that SDG&E will begin transitioning eligible customers to default TOU rates in March 2019. The California Solar and Storage Association filed a motion in June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's	Docket No. A-17-12-013 Docket No. A-19-03-002 December 2018 Decision

	rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. On December 13, 2018, the Commission issued a decision which largely adopted the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers. An evidentiary hearing took place in January 2019. SDG&E filed its revised TOU rates in a new proceeding (Docket No. A-19-03-002) in March 2019.	
Time-Varying Rates	Southern California Edison (SCE) filed its proposed default TOU rates in December 2017. SCE is seeking approval of two default "TOU Light" rates, which use slightly different peak periods and feature seasonally-differentiated tiers. Both rates were previously approved for SCE's Default TOU Pilot, which is expected to roll out in March 2018. SCE will select the lowest cost rate when implementing its default TOU rate beginning in October 2020 and concluding 15 months later. The California Public Utilities Commission issued a scoping ruling in March 2018 and an amended scoping ruling in April 2018. The two rulings establish the scope of issues that will be discussed across three phases and the schedule for the remainder of the proceeding. Phase I will resolve questions related to the proposed start dates for the default TOU rates. Phase II will consider the utility's specific TOU rates, and Phase III will consider the utility's proposals for fixed charges and/or minimum bills. A May 2018 Decision from the CPUC established that SCE will begin transitioning eligible customers to default TOU rates starting in October 2020. The California Solar and Storage Association (CCSA) filed a motion June 2018 to clarify that the scope of the proceeding includes a consideration of alternative, non-dynamic rate designs. A July ruling affirmed that alternative, non-dynamic rate designs are within the scope of the proceeding. A proposed decision filed in November 2018 approves SDG&E's proposed rates, but defers a decision on PG&E's rates, since they will have a later rollout. The proposed decision does, however, approve proposals by PG&E and SCE to implement a line item discount for CARE customers. On December 13, 2018, the Commission issued a decision which largely adopted the proposed decision, with the addition that virtual net metering and net metering aggregation customers will not be included in the transition to default TOU rates due to issues with rate comparison calculation for these customers. An evidentiary hearing took	Docket No. A-17-12-012 December 2018 Decision

	place in January 2019. An email ruling filed in March 2019 requested additional information from SCE.	
Utility Business Model Reform	An ongoing proceeding in California is investigating DER integration methods. The scope of the proceeding includes: (1) the development of a competitive solicitation framework for DERs, (2) the continued development of technology-neutral cost-effectiveness methods and protocols, (3) leveraging the work performed in the Distribution Resource Plans proceeding (see Planning and Market Access), and (4) the role of the utilities, business models, and financial interests in DER deployment. A December 2016 decision established a Competitive Solicitation Framework and a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for investments in traditional distribution infrastructure. The specific incentive adopted for the pilot was 4% pre-tax applied to the annual payment for the DER alternative to the traditional distribution investment. The decision required each utility to identify one DER project, with the option of identifying up to three additional projects to test the incentive mechanism. A June 2018 decision addressed cost recovery for the Incentive Pilot program. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report on its Streamlined Competitive Solicitation Framework and Utility Regulatory Incentive Mechanism pilot. The report indicates that SDG&E launched its Pilot Request for Offers in January 2018 and did not receive any conforming bids that were cost effective. the report presents a series of recommendations for improving the process, and the Commission opened a comment period on the report. In January 2019, the Commission issued a ruling directing parties to respond to questions regarding the development of a stakeholder process for updating the Avoided Cost Calculator. A Proposed Decision filed in March 2019 adopts the new cost-effectiveness analysis framework policies for DERs. The proposed decision states that the Total Resource Cost (TRC) test will be the primary test of cost-effectiveness for all DER beginning on July 1, 2019 which require cost-effectiveness analyses. The proposed decision additionally clarifies that the modified TRC, Program Administrator Cost (PAC), and Ratepayer Impact Measure (RIM) tests will be used as replacements for the existing tests. Lastly, the proposed decision establishes that the three-element Societal Cost Test (SCT) to be tested through December 31, 2020 for planning purposes in the integrated resource planning proceeding. The three elements of the SCT are a	Docket No. R-14-10-003 Proposed Decision

		societal discount rate, an avoided social cost of carbon, and an air quality adder value.	
DE	Ratemaking	Senate Substitute 1 for S.B. 80, enacted in June 2018, allows utilities to apply a Distribution System Improvement Charge (DSIC), subject to the approval of the Public Service Commission. The bill identifies eligible distributed system improvements as new, used and useful electric utility plant projects that do not increase revenues by connecting the distribution system to new customers, are in service, and satisfy one of four additional criteria related to the equipment being replaced. The Commission opened a proceeding in early October 2018 to develop regulations. The Staff presented proposed regulations in, which the Commission adopted. Delmarva then filed a motion to modify a part of the regulation, which the Commission also accepted. Delmarva filed comments in November 2018 requesting additional changes to the regulations.	Reg. 64 Senate Sub 1 for S.B. 80 (2018)
HI	Rate Reform	A March 2019 order approving Phase 1 of HECO's grid modernization plan also directed the utilities to develop a succinct Advanced Rate Design Strategy that describes how the utilities will leverage the technological capabilities of advanced meters to support their planned programs and the Commission's stated priorities. The Strategy should briefly describe the utilities' plans to offer advanced rate designs and include advanced rate design proposals for further development and consideration. The Strategy should also include a timeline for the utilities to offer updated dynamic rates for all residential and commercial customers (including, the introduction of time-varying rates, critical peak pricing, and real time pricing rate structures); potential rate reform considerations to support low-income customer participation; enrollment mechanisms for convenient customer participation in the advanced rate offerings; implementation plans for offering advanced rates, including education and outreach to customers; and evaluation plans for monitoring, verifying, and improving the effectiveness of advanced rate designs.	Docket No. 2018-0141 Docket No. 2014-0192 Order
	Utility Business Model Reform	The Public Utilities Commission opened a new proceeding in April 2018 to investigate the economic, technical, and policy issues associated with performance-based regulation for the HECO companies. The proceeding will be divided into two phases. Phase 1 will evaluate the current regulatory framework and identify which incentive mechanisms may not be functioning as intended, and to identify specific areas that should be targeted for improvement. In Phase 2, the Commission will work	Docket No. 2018-0088 Staff Report

		collaboratively with stakeholders to refine elements of the existing regulatory framework, develop incentive mechanisms to better address specific objectives, and explore alternative regulatory frameworks. The Commission held technical workshops in July and September 2018. The Commission Staff issued a concept paper in September 2018 to provide parties with a common understanding and suggested approach for assessing a revised set of potential regulatory outcomes, with respect to current regulatory mechanisms. The Commission Staff released a third concept paper and hosted a third technical workshop in November 2018. Parties filed briefs on performance metrics in early January 2019. The Commission Staff filed a proposal for updated performance-based regulations in February 2019. The proposal recommends 12 priority outcomes to guide the remainder of the proceeding, and includes a portfolio of performance-based regulations designed to meet those outcomes. The portfolio includes revenue adjustment mechanisms, performance mechanisms, and other mechanisms. The Staff recommend developing new reported metrics based on affordability, customer equity, transportation electrification, capital formation, and resilience. The Staff also recommend new scorecards based on interconnection experience, customer engagement, cost control, and greenhouse gas reduction, as well as new performance incentive mechanisms based on interconnection experience, customer engagement, and DER asset effectiveness. There is currently a performance incentive mechanism for reliability that would also remain in place under the Staff's proposal. Performance incentive mechanisms would provide utilities with a financial incentive, while scorecards would only report the metric and provide a benchmark and target, and reported metrics would only be tracked. Parties filed their statements of position in March 2019. Among other suggestions, the Division of Consumer Advocacy recommended including customer satisfaction and cybersecurity as priority outcomes. The HECO utilities provided several recommendations and suggested that new performance incentive mechanisms be focused on acquisition, integration, interconnection, and utilization of DERs; advancement of community-based renewable energy; and a sustained incentive for acquisition of renewable energy resources.	
IL	Time-Varying Rates	In November 2018, Commonwealth Edison filed a residential TOU pricing pilot tariff. The tariff uses a three-part supply rate with "super peak," peak, and off-peak hours. The pilot will be available for 4 years. Commonwealth Edison also filed a request to revise	[Docket No. 18-1824]()

		its Integrated Distribution Company Implementation Plan to allow for the promotion, advertising, and marketing of the pilot program. A prehearing conference took place in January 2019, and in March 2019, the ALJ postponed the hearing date to April 18, 2019.	
	Utility Business Model Reform	H.B. 3152 and S.B. 2080 make several changes to the performance-based formula rate for utilities participating in the infrastructure investment program under Section 16-108.5 of the Public Utilities Act. It would allow the infrastructure investment program to continue past 2022.	H.B. 3152 (I) S.B. 2080 (I)
IN	Ratemaking	H.B. 1470 allows utilities to include advanced technology investments, including AMI and DER management systems in their transmission, distribution, and storage system investment plans (TDSIC plans). Utilities are given automatic adjustments to their base rates to cover 80% of the cost of investments made under TDSIC plans. The bill passed the House in February 2019, and the Senate in March 2019.	H.B. 1470 (P2)
KS	Time-Varying Rates	In early February 2019, Kansas City Power & Light filed an application to modify its residential TOU rates. The revision would exclude holidays and weekends from peak periods. In mid-March 2019, the Commission Staff filed a report recommending approval of the application. In late March 2019, the Commission issued an order adopting the recommendations from the Staff report. Kansas City Power & Light filed its revised tariffs in mid-April 2019.	Docket No. 19-KCPE-318-TAR
KY	Fixed Charges	H.B. 16 requires that fixed customer charges recover no more than fixed capital costs for metering, billing, service connections, and customer service. The bill did not advance during the 2019 legislative session.	H.B. 16 (D)
LA	Ratemaking	As part of Entergy New Orleans' general rate case filed in September 2018, the utility requested approval for a new cost recovery mechanism for its demand-side management (including demand response) initiatives. Entergy proposed a new rider, Rider DSMCR, to fund its Energy Smart programs for program year 10 and beyond. The proposed rider would include direct and indirect costs of the demand-side management offerings, lost contributions to fixed costs, and some type of an incentive. Entergy would earn a return on its demand-side management offerings, in order to put demand and supply resources on a more equal footing.	City Council Docket No. 18-07
MA	Fixed Charges,	S. 2007 directs the Department of Public Utilities (DPU) to open a proceeding to establish specific	S. 2007 (I)

Time-Varying Rates, Utility Business Model Reform	metrics and performance incentives for evaluating utility progress toward a grid planning system that uses local energy resources to meet customers' needs. These metrics may include reducing the impact of outages, optimizing demand, integrating local energy resources, improving workforce and asset management, and electrification resulting in lower greenhouse gas emissions and energy cost savings, after accounting for fuel switching. The bill also prohibits the DPU from approving a residential fixed charge that is higher than the investment costs and operation and maintenance expenses directly related to the cost of connection (not including AMI used to provide energy services), billing, and providing customer service. Furthermore, the bill requires IOUs to offer default service customers a TOU rate option by January 2020.	
Utility Business Model Reform	Among other requirements related to distribution system planning, H. 2808 and S. 1932 direct the Department of Public Utilities to open a proceeding to establish specific metrics and performance incentives for evaluating utility progress toward a grid planning system that uses local energy resources to meet customers' needs. These metrics may include reducing the impact of outages, optimizing system performance, interconnecting and integrating local energy resources, improving workforce and asset management, and beneficial electrification.	H. 2808 (I) S. 1932 (I)
Utility Business Model Reform	In Eversource's latest general rate case, filed in January 2017, the utility requested approval of a performance-based ratemaking (PBR) mechanism, whereby rates would be adjusted annually in accordance with a revenue-cap formula. The Department of Public Utilities (DPU) issued an order in November 2017 on the revenue requirement portion of the case, approving Eversource's proposed PBR mechanism, including an earnings sharing mechanism (25% to shareholders and 75% to ratepayers). The DPU ordered Eversource to submit metrics and benchmarks for customer satisfaction/engagement and system peak demand reduction, as well as a climate adaptation plan to use in developing future metrics and benchmarks related to climate adaptation and greenhouse gas emissions reduction. In March 2018, Eversource filed its proposed PBR metrics, which fall into three categories: improvements to customer service/engagement, reductions in system peak, and strategic planning for climate adaptation. Within the customer service category, Eversource proposed the following metrics: (1) overall customer satisfaction, (2) customer	Docket No. 18-50 Docket No. 17-05 Order Establishing Eversource's Revenue Requirement

	engagement (customer engagement platform, use of outage map, social media engagements, and digital engagement), (3) producer satisfaction (based on a satisfaction survey), and (4) producer engagement (based on the producer portal). For the peak reduction category, the utility will work to reduce system peak through company-controlled measures in energy efficiency, demand response, company-owned storage, company-owned solar, upgrading standard technology, volt/VAR optimization, and reduced line losses. Eversource notes that it will also produce an annual report on peak load reduction through time-varying rates and DG tracking. For the climate adaptation planning, Eversource plans to (1) deploy 7,000 low loss transformers over five years, (2) establish design leak rates for SF-6 containing equipment, (3) replace 45% of fleet diesel with biofuels, (4) transition 25% of facility square footage to LED or energy-efficient lighting by 2020, (5) install 62 MW of solar, (6) deploy a grid-connected storage project to displace the need for diesel generators, (7) study volt/VAR optimization efforts and associated emissions, (8) prioritize substations at flooding risk, (9) evaluate new equipment to improve performance in floods, (10) harden the overhead system, and (11) augment the outage prediction model to include the climate impacts of flooding. In June 2018, the DPU opened a new docket for review of the proposed PBR metrics. The Attorney General's Office of Ratepayer Advocacy filed testimony in September 2018, finding that Eversource's proposed metrics "fail to identify, quantify, or ensure any measurable benefits to customers that can be attributed to a PBR form of rate regulation." An evidentiary hearing was held in late October 2018, and parties filed briefs in November 2018. Eversource filed an initial brief in early December 2018, discussing its proposed PBR metrics.	
Utility Business Model Reform	In November 2018, National Grid filed a general rate case, which includes a performance-based ratemaking (PBR) plan that would replace the capital investment recovery mechanism. National Grid proposed four performance incentive mechanisms: (1) peak reduction (measured by total incremental MW contributions from utility owned or influenced measures during the top five peak events of the summer for a maximum of three hours at a time), (2) electric vehicle adoption (measured by increased electric vehicle adoption in the utility's service territory above forecasted business as usual), (3) electric vehicle supply equipment cost containment (measured by cost-efficient delivery of charging ports	Docket No. 18-150

		in the proposed Phase II Electric Vehicle program), and (4) customer ease (measured by the "customer ease score" reflecting how easy it is for customers to interact and do business with the utility). National Grid also proposed three "scorecard metrics" which will not be tied to performance incentives, but will help make the utility's performance more transparent. These scorecard metrics are: (1) greenhouse gas emissions reduction, (2) customer engagement, and (3) DER customer experience. Public hearings are scheduled for March 2019.	
MD	Time-Varying Rates	As part of Maryland's grid modernization proceeding (Public Conference No. 44), utilities are developing pilot programs for time-varying rates. In August 2017, the Rate Design Working Group submitted its report. The group noted that although the working group members agreed on discrete elements, the group was unable to reach consensus on the design of the pilot program. The report recommended a pilot program that tries to best reflect the different viewpoints discussed in the group. In November 2017, the PSC published an order stating that the materials submitted by the rate design working group are not yet sufficiently specific to approve the TOU pilot programs. The PSC directed the working group leaders to continue convening the group to refine the pilot program designs. In February 2018, the working group filed its revised report with detailed descriptions of the proposed TOU pilots. The report identifies six decision points for the pilot programs to move forward. The Commission issued a letter order in May 2018, addressing each of the six decision points developed by the working group, and requesting that the utilities proceed with their rate design pilots. The utilities filed a joint implementation plan and updated budgets in late May 2018 and requested a modification to the pilot program development timeline, which would have the pilot rates begin no later than April 2019. The Commission approved the joint utilities' request in June 2018. In keeping with the timeline, the joint utilities filed their Marketing and Outreach plans in July 2018 and parties provided comments. In December 2018, the PSC directed the utilities to proceed with implementation of the TOU pilots. The utilities filed their revised TOU pilots, which the Commission approved in March 2019.	Public Conference No. 44
ME	Decoupling	As part of Emera Maine's general rate case filed in March 2019, the utility proposed a new revenue decoupling mechanism. Emera originally suggested a revenue decoupling mechanism as part of its recommendations in the non-wires alternatives	Docket No. 2019-00019

	proceeding (Docket No. 2018-00171). The decoupling mechanism will be applied to the residential and commercial and industrial customer classes.	
Utility Business Model Reform	L.D. 1173 allows generators to sell electricity directly to commercial and industrial customers without being classified as a public utility. The generator and the customer must be located within five miles of each other, and the bill limits direct electric service to five customers.	L.D. 1173 (I)
Utility Business Model Reform	In April 2016, the Public Utilities Commission (PUC) opened an investigation into the designation of a Non-Transmission Alternative (NTA) Coordinator, and a final order was published in December 2017. The Commission found that the state's distribution utilities, Central Maine Power and Emera Maine, have the best knowledge of the system, as well as the technical and engineering knowledge necessary to perform the role of the NTA Coordinator. However, the PUC noted that incentives in existing ratemaking encourage the utilities to invest in wires solutions over non-wires alternatives. Therefore, the PUC directed the utilities to file, within six months, proposals to address this incentive so that wires and non-wires solutions are on an equal footing from a ratemaking perspective. In June 2018, the utilities filed their NTA report, which recommends (1) the establishment of a revenue decoupling mechanism for Emera, (2) the establishment of ratemaking approaches that treat situations expenditures related to non-wires alternatives (NWA) similar to traditional transmission and distribution investments, (3) incentives for the utilities to plan for and deploy NWA, (4) the establishment of a process to review utility NWA plans similar to utility transmission projects, (5) ratemaking tools for timely recovery of NWA costs, and (6) an approach to address innovative and cost-effective grid modernization projects, including pilots and demonstration projects, to develop ways of increasing efficiency and supporting future NWA projects. An initial case conference was held in July 2018, and the utilities filed a supplemental NTA report in October 2018. The PUC Staff filed a bench memorandum with its proposed ratemaking and process alternatives in December 2018. The Staff recommended that for Emera, a revenue decoupling mechanism be considered as part of a more comprehensive rate review and that different ratemaking approaches be taken for transmission-level NWAs and distribution-level NWAs. For transmission NWAs, costs would be recovered through an annual rate adjustment and investments/capitalized expenses could earn a return	Docket No. 2018-00171 Docket No. 2016-00049

		at the utility's FERC-authorized rate of return. Any costs not allowed in FERC-jurisdictional transmission rates could be recovered through the distribution rate adjustment. For distribution NWAs, costs would also be recovered through an annual rate adjustment, with the utility earning a return at the rate of return on rate base approved by the PUC. Transmission NWA costs would be allocated to all utility customers, while distribution NWA costs would be allocated only to customers taking service at distribution voltages. For third-party owned NWAs, expenses would be capitalized through a service agreement, lease, or contract, and any expenses not capitalized could be recovered in the distribution rate adjustment. The Staff proposed that any ratemaking incentive program be structured as a pilot program. The staff also proposed that the utilities provide additional detail on the internal processes for considering NWAs and that the utilities file annual reports that detail capacity and load by circuit and identify all growth-related investments for the next three years. The Office of the Public Advocate also filed recommendations in December 2018, recommending that the Commission reject the utilities' proposal, that the utilities file a complete financial model with earnings and ratepayer savings under different shared savings mechanisms, that a shared savings mechanism with 30% savings retained by utilities be approved, that capitalization of NWA expenses be approved, that utilities only be allowed to recover NWA incentives once capacity benchmarks are reached, and only allow recovery of capitalized NWA assets beginning at the time of the next rate case, but allow recovery of NWA expenses on a current basis. The utilities filed supplemental information on NWA screening in late March 2019, and the PUC denied the Office of the Public Advocate's (OPA) request for a stay. The OPA had requested a stay because the state legislature is currently considering a bill related to non-wires alternatives.	
MI	Time-Varying Rates	In an April 2018 order resolving a general rate case for DTE Electric that began in 2017, the Commission ordered DTE to begin moving to default TOU rates in its next rate case. In July 2018, DTE filed a new rate case that includes default TOU rates for residential customers. A proposal for decision was issued in March 2019. The proposal includes the default TOU rates for residential customers.	Docket No. U-20162 Docket No. U-18255
	Utility Business Model Reform	In May 2018, Consumers Energy filed a proposal for reconciliation of its demand response costs, including a financial incentive mechanism to encourage the use of demand response. The proposed incentive would allow the utility to earn 20% on all expenses	Docket No. U-20164

		associated with "building" and using demand response programs and resources. A hearing took place in February 2019.	
MN	Utility Business Model Reform	Minnesota statutes allow utilities to establish multi-year rate plans for a period of up to five years. The same statutes provide that the Commission may require a utility operating under a multi-year rate plan to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies. The Commission noted that during Xcel's most recent rate case, the record was insufficient to determine the adequacy of its performance metrics. The Commission opened a new proceeding in September 2017 to reach an understanding of the combination of metrics and incentives that could appropriately align utility and ratepayer interests. The docket is proceeding in two phases, with the first phase collecting stakeholder input on the key goals for the electricity sector and how to measure its progress toward meeting those goals. The second phase is focusing on how those performance measurements could be applied by the Commission. After a period of inactivity, the Commission examined this matter in its November 1, 2018 agenda meeting. The Commission authorized its Executive Secretary to issue notices, set schedules, and designate comment periods for the development of performance incentive mechanisms. The process will also include several stakeholder workshops. The Commission selected Great Plains Institute as a facilitator. In January 2019, the Commission issued an order adopting the performance incentive mechanism development process proposed by the Office of the Attorney General. A workshop was held in March 2019.	Docket No. 17-401 E21 Initiative
MO	Time-Varying Rates	In February 2019, Kansas City Power & Light filed an application to modify its residential TOU rates. The revision would exclude holidays and weekends from peak periods. The Missouri Public Service Commission issued an order approving the revised tariffs in March 2019.	Docket No. ET-2019-0237
	Time-Varying Rates	In February 2019, Kansas City Power & Light Greater Missouri Operations filed an application to modify its residential TOU rates. The revision would exclude holidays and weekends from peak periods. The Missouri Public Service Commission issued an order approving the revised tariffs in March 2019.	Docket No. ET-2019-0238
MT	Utility Business Model Reform	H.B. 438, the "Electric Utility Industry Restructuring and Customer Choice Act," directs public utilities to conduct pilot programs with residential and small commercial customers to gather information on the	H.B. 438 (D)

		most effective and timely options for providing customer choice. The pilots are to begin in July 2020. The bill requires that by July 2020 customers with loads greater than 1,000 kW have the opportunity to choose their electricity supplier. By July 2024, all other public utility customers are to have the opportunity to choose their electricity supplier. If additional time is needed, this transition may not occur later than July 2026. Utilities are to file transition plans one year before customer choice is implemented. Vertically integrated utilities will be required to divest themselves of generation assets. Utilities will be required to file tariffs to make transmission and distribution services available to all electricity suppliers. The bill was tabled in committee.	
NC	Fixed Charges	In compliance with a June 2018 order, the Public Staff submitted a report on the use of the minimum system methodology in March 2019. The minimum system methodology has been used by the utilities since the early 1970s to determine the fixed monthly customer charge. The report finds that each of the three IOUs in North Carolina use slightly different methods for estimating the minimum system. The Public Staff's report ultimately recommends that the use of the minimum system methodology for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge. The report further recommends that the minimum amount recovered in the fixed charge for any rate class should be an amount determined by the "basic customer method" which reflects the customer meter, service drop, and any other facilities uniquely attributable to specific customers that are not already recovered through extra facilities charges. Further, any increase in the fixed charge for any rate class should not exceed an amount that would recover more than 25% of the revenue increase that was assigned to that customer class.	Docket No. E-100 Sub 162 Report
	Rate Reform, Time-Varying Rates	In August 2017, Duke Energy Carolinas filed a general rate case, which was decided in June 2018. Various parties to the docket suggested that Duke should develop additional TOU or critical peak pricing options for customers. The Commission, however, was not persuaded based on the pilot rates previously implemented. The order does not adopt new TOU or critical peak pricing options, but it does require Duke to file proposed dynamic rate structures. In December 2018, Duke filed a report on plans for AMI and Customer Connect-enabled rate design, pursuant to the Commission's June 2018 order. The report notes that Duke will evaluate a redesigned residential TOU rate, a residential fixed bill rate, a residential variable	Docket E-7 Sub 1146 Revised Rate Design Report

		peak pricing rate, small commercial TOU and variable peak pricing rates, and large commercial/industrial TOU and variable peak pricing rates. Duke noted that it will file at least two pilots (one for residential customers and one for general service customers) at the time of its next rate case. Duke Energy filed its revised AMI Rate Design Work Plan and Proposed Dynamic Pricing Pilots in early April 2019. The Workplan includes a revised timeline to reflect accelerated implementation of the new Customer Connect billing system in Spring 2021. Rather than filing two proposed AMI rate design pilots as required by the Commission, Duke filed nine dynamic price pilots. The pilots include three different rate designs for residential, residential all-electric, and small commercial and industrial rate classes.	
NH	Energy Storage Tariff	In December 2017, Liberty Utilities filed an application to implement a battery storage pilot program, in which the utility will deploy 5 MW total of battery storage equipment at the homes of 1,000 residential customers. The utility is also requesting approval for a TOU rate for program participants, which includes critical peak, on-peak, and off-peak periods. Multiple parties generally expressed support for the program as a pilot, but concern about the proposed TOU rate not being more broadly available. A settlement agreement was filed in November 2018, which approves the program with modifications. The settlement approves a smaller version of the proposed program, and establishes a working group to develop a "Bring Your Own Device" program to deploy 500 additional batteries deployed by third parties. In January 2019, the Commission issued an order approving the battery storage program as detailed in the settlement agreement.	Docket No. 17-189 Order No. 26,209
	Time-Varying Rates	In the New Hampshire Public Utilities Commission's June 2017 net metering successor tariff order, the Commission ordered the implementation of four pilot programs, including one on TOU rates (Eversource and Unitil) and one on real-time pricing (Liberty Utilities / City of Lebanon). The TOU pilots will be open to both residential and small commercial customers. The order requires that the data from these pilot programs be made available to a broad range of stakeholders. A working group on TOU rate pilots has been meeting, and one utility previewed a potential TOU rate approach. The working group met again in July 2018 and February 2019.	Docket No. DE 16-576 Order No. 26,029
	Time-Varying Rates	In February 2019, Unitil filed its proposed TOU study, pursuant to Order No. 26,029 in Docket No. 16-576 (net metering successor tariff proceeding). Under the	Docket No. 19-033

		proposed program, the time-varying rates would apply to both consumption and net excess generation from customer DG systems. The proposed study includes a "table top quantitative analysis of TOU rate structures" and a qualitative assessment of key TOU rate-related questions and topics. Unitil notes that stakeholders will have a significant role in the study process. Unitil plans to focus on TOU block pricing, but will explore hourly energy pricing, particularly for DG and storage customers. According to Unitil's proposed schedule, the utility would determine TOU blocks and rate designs to analyze between June 2019 and October 2019. The final report on the study would be completed by April 2020. A technical session was held in April 2019.	
NJ	Decoupling	As part of Atlantic City Electric's general rate case filed in August 2018, the utility proposed a decoupling mechanism, designed as an annual rate adjustment. A settlement agreement filed in late February 2019 withdraws the revenue decoupling mechanism. The Board of Public Utilities approved the settlement agreement in March 2019.	ACE Petition (Docket No. 18080925) Decision and Order Adopting Initial Decision and Stipulation of Settlement
	Time-Varying Rates	S.B. 603 and A.B. 3732, introduced in January and March 2018, direct the Board of Public Utilities to open a proceeding to allow the state’s utilities to deploy AMI throughout their service territories. Upon completion of the Board’s proceeding, each utility is to file a proposed smart meter procurement and installation plan. The bills state that utilities and electric power suppliers may offer TOU rates and real-time pricing programs after deploying AMI. The bills also state that residential and commercial customers may elect to participate in these rate programs.	A.B. 3732 (I) S.B. 603 (I)
NM	Decoupling	Pursuant to the New Mexico Public Regulation Commission's final order approving a modified revised stipulation in PNM's latest general rate case, a new docket was opened in March 2018 to address regulatory barriers and disincentives to energy efficiency and load management programs. The proceeding is intended to provide stakeholders with an opportunity to develop a mechanism to remove these disincentives, which can then be implemented in PNM's next rate case. PNM proposed a Lost Contribution mechanism for the residential and small power service classes to remove these disincentives. The mechanism would be comprised of an authorized fixed cost recovery factor, a lost fixed cost amount, and a lost contribution rider rate. In December 2018, the Coalition of Clean Affordable Energy, New Mexico	Docket No. 18-00043-UT

		Attorney General, and PNM requested that the Hearing Examiner hold the proceeding in abeyance until the end of the 2019 state legislative session. The Hearing Examiner granted the motion.	
	Decoupling	H.B. 291 and S.B. 136, introduced in December 2018, authorize the Public Regulation Commission to remove regulatory disincentives or barriers for utility expenditures on energy efficiency and load management measures, either upon petition or on its own motion. The bills specifically authorize the Commission, upon petition by a public utility, to remove regulatory disincentives through adoption of a rate adjustment mechanism. The Governor signed H.B. 291 into law in early April 2019.	H.B. 291 (E) S.B. 136 (D)
NY	Rate Reform	As a part of the Reforming the Energy Vision Track Two order, the Public Service Commission (PSC) required the utilities to provide in detail the cost allocation methodologies being used to calculate standby rates. The PSC also directed the utilities to file revisions to their standby service rates to implement offset tariff and reliability credit provisions for standby customers who are able to demonstrate that they are able to reduce their load below contract demand over consecutive summer periods. The utilities filed their tariff amendments in August 2016, which became effective on January 1, 2017 after including revisions ordered by the PSC. In July 2017, the PSC issued an order moving this proceeding into the Value of Distributed Energy Resources (VDER) proceeding's Rate Design Working Group (Matter No. 17-01277). The Staff issued a draft outline for a standby/buyback white paper in February 2018. The outline includes a recommendation to require utilities to develop more granular as-used demand charges, with time and location variant components, depending on the cost driver of the distribution system. In December 2018, the Staff published a white paper recommending modifications to existing standby and buyback service rates.	Docket No: 17-01277 Docket No. 16-M-0430
	Rate Reform	In May 2017, as part of the Public Service Commission's (PSC) Reforming the Energy Vision Track Two order, the PSC directed the staff to publish a report regarding scope, feasibility, and deliverables on an analytical approach to examining bill impacts of a range of opt-out variable rate scenarios (i.e. time-varying rates, demand charges, coincident-peak demand charges) for residential and commercial customers. In October 2017, the staff published its scope of a study to examine bill impacts. The staff will consider rate design structures, billing determinants, and calculate revenue-neutral rates based on the PSC's rate design principles. In January 2018, the	Docket No. 17-01277 Docket No. 15-E-0751/15-02703

	staff provided further guidance for utilities to guide the bill impact study. Several workshops were held during Q1 2018. In April 2018, the PSC requested that stakeholders submit rate design proposals, and the utilities published a Rate Design Handbook to define and explain the uniform approach they have developed for parties to submit rate design proposals. During Q2 of 2018, stakeholders submitted proposals based on the framework established by the PSC. In late June 2018, the PSC announced which rate design proposals will be evaluated. The proposals to be evaluated include a time-of-use (TOU) rate proposal submitted by the clean energy parties, a time-of-use rate proposal by PSC Staff, a demand rate proposal by the joint utilities, and a combined demand and TOU rate proposal by the joint utilities. The utilities and the consultant serving the PSC completed rate design evaluations during August 2018, and a working group meeting was held in October 2018 to discuss the evaluations.	
Rate Reform	In July 2018, Consolidated Edison (ConEd) filed a proposal for a pilot innovative pricing program. The innovative pricing options will be available to residential and small commercial customers. The options include demand-based rates and subscription rates (fixed monthly charge based on the customers' prior electric demand). Several variations are included to test customer satisfaction, acceptance, behavior, and bill impact. Variations include peak and off-peak demand charges, seasonal demand charges, peak period timing, TOU supply components, and overage charges for subscription rates. In December 2018, the Public Service Commission approved the Innovative Pricing Pilot. ConEd expects to enroll approximately 67,100 customers in the pilot. The pilot will begin in April 2019 and will end after the first quarter of 2022. The pilot will test the innovative rates enabled by AMI. On March 1, 2019, ConEd requested an emergency update to its tariff for the project to adjust demand rates downward by 4.1% based on revised data. The PSC approved the tariff adjustment on March 18, 2019.	Docket No. 18-01597/18-E-0397
Rate Reform	In May 2016, the New York Public Service Commission (PSC) issued an order that required utilities to develop Smart Home Rate (SHR) demonstration projects. Smart Home Rates are intended to combine time-based pricing with location and time-based compensation for distributed energy resources; the rates would be intended to incentivize home energy management responses, and would be available on an opt-in basis. All of the major utilities filed SHR proposals in February 2017. PSC Staff filed assessment reports reviewing the proposals during	Docket No. 18-02038/18-E-0548 Docket No. 18-02039/18-E-0549 Docket No. 14-00581/14-M-0101

	2018; the report for Con Edison and Orange & Rockland was published in June 2018, the reports for National Grid and CHG&E were published in July 2018, and the reports for NYSEG and RG&E were published in September 2018. Con Edison and Orange & Rockland filed an implementation plan for their project in August 2018. CHG&E filed a close-out report for its SHR program in early April 2019.	
Rate Reform	On February 15, 2019, National Grid proposed to modify its Clifton Park demand reduction demonstration project by changing it from an opt-in to an opt-out structure and adding two new pricing structures. The two pricing structures to be tested are referred to as the AMI Rate and the Beneficial Electrification Rate; the AMI Rate includes time-of-use (TOU) and critical peak pricing (CPP) rates, while the Beneficial Electrification Rate includes both the TOU/CPP rates and a two-demand delivery charge (a demand charge incorporating both individual and coincident peak demand elements).	Docket No. 19-E-0111
Utility Business Model Reform	In May 2016, as part of Track Two of New York's Reforming the Energy Vison proceeding, the Public Service Commission (PSC) directed the utilities to propose a DG interconnection survey process and Earning Adjustment Mechanism (EAM) metrics. The EAM will provide utilities with diverse, balanced financial incentives to implement REV outcomes. In September 2016, the utilities proposed EAM metrics, as well as specific targets and incentives to be developed. In March 2017, the PSC ordered the utilities to file a revised proposal with modifications provided by the PSC. In May 2017, the utilities published a revised EAM proposal, and in August 2017, the utilities filed a supplemental interconnection EAM survey instrument. In October 2018, the Commission Staff filed a proposal related to the interconnection EAM. Parties filed comments on the proposal in December 2018 and January 2019.	Docket No.16-01575/16-M-0429
Utility Business Model Reform	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the PSC adopted an energy storage target and roadmap for deploying 1,500 MW of storage by 2025 and 2,000 MW by 2030. As part of the roadmap, the PSC directed the utilities to file in their next general rate case an Earning Adjustment Mechanism metric for system efficiency. The system efficiency target is to include peak reduction and load factor. The utilities	Docket No. 18-00516/18-E-0130 NYSERDA Website

		filed implementation plans for competitive procurement of energy storage systems, including the proposed ratemaking and accounting treatment, in February 2019.	
OH	Ratemaking	In February 2019, First Energy filed an application for a two-year extension of its Distribution Modernization Rider (Rider DMR). The Commission originally approved Rider DMR for three years in 2016 and it is due to expire at the end of 2019. Parties filed testimony in March 2019.	Docket No. 19-0361-EL-RDR
OK	Utility Business Model Reform	In September 2018, as part of a general rate case, Public Service Company of Oklahoma proposed a grid modernization and efficiency plan, which includes the adoption of performance-based rates. The plan would establish certain "performance incentive measures" related to reliability, grid modernization, customer satisfaction, public safety, and economic development, and would set a range of allowable return on equity levels (9.8-10.8%) based on actual financial performance. The reliability incentive is based on SAIDI figures, and the grid modernization incentive is based on the utility executing its grid modernization investment plan on-time and within a certain budget. The customer satisfaction incentive is based on survey results, the public safety incentive is based on responding to reported hazards, and the economic development incentive is based on the utility participating in and supporting local workforce development events. Performance-based rate adjustments would take place annually. Parties filed their lists of major issues for the proceeding and filed testimony in January 2019. A settlement agreement was filed in late February 2019, which does not include the performance incentive measures or cost recovery for grid modernization. A Distribution Reliability and Safety Rider would provide for $5 million per year in distribution investments. The settlement agreement was approved on March 14, 2019.	Docket PUD-201800097 Press Release
OR	Critical Peak Pricing, Time-Varying Rates	Portland General Electric filed a request to implement its Flexible Residential Pricing Program (Flex 2.0) in February 2019. Flex 2.0 moves from the Flex 1.0 pilot with two optional pricing programs for its residential customers. The Opt-in Peak Time Rebate program provides an incentive to customers who use less electricity during critical peak events. Participants will be notified prior to the event. After the event, Portland General Electric will measure the customer's energy reduction compared to the customer's baseline usage to determine the amount of hourly kilowatt reduction and the amount of the rebate. The other rate is a TOU rate with optional participation in peak-time events,	Docket No. ADV 920

		though Portland General Electric submitted a supplemental filing in March 2019 to withdraw its request for the TOU rate. Portland General Electric stated that it will hold a meeting with the Commission Staff about TOU in April 2019 and will refile a TOU rate later.	
	Time-Varying Rates	In December 2018, Idaho Power filed an application for approval of a TOU pilot rate for its residential customers in Oregon. The rate would be offered on an optional, voluntary basis to customers with AMI installed.	Docket No. ADV 901
RI	Utility Business Model Reform	This proceeding was opened in August 2018 for adoption of performance incentives to apply to the electric infrastructure, safety, and reliability plans. Technical sessions are scheduled for April 4, 2019 and May 14, 2019. A hearing is scheduled for August 15, 2019.	Docket No. 4857
	Utility Business Model Reform	In October 2018, National Grid filed its 2019 System Reliability Procurement Report. In the report, the utility proposed performance incentives for 2019 SRP work. The incentives include (1) a 2% (of the 2019 SRP budget) incentive for identifying areas where large non-electric public transportation fleets are located, as part of the work on the Rhode Island System Data Portal; (2) a 2% incentive for identifying locations where electric vehicle fast charging stations can be installed; and (3) a 2% incentive for awarding and completing the first vendor milestone for three non-wires alternatives projects. A hearing was held in December 2018.	Docket No. 4889 2019 System Reliability Procurement Report
SC	Fixed Charges, Demand Charges, Time-Varying Rates	H.B. 3659, as amended, requires the Commission to ensure that each electrical utility offers to each class of service a minimum of one reasonable rate option that aligns the customer's ability to achieve bill savings with long-term reductions in the overall cost the electrical utility will incur in providing electric service, including, but not limited to time-variant pricing structures. As originally introduced, the bill would have prohibited residential rates from including a bill component based on non-coincident peak demand or including a fixed charge that exceeds the costs of providing a service drop, metering, billing, and customer support. Furthermore, the bill prevents the Public Service Commission from approving an increase in a utility's fixed charge that exceeds its percentage retail rate increase for each class. The House passed the amended bill in February 2019.	H.B. 3659 (P1)
	Utility Business Model Reform	S.B. 137 requires the commission to establish performance incentives and penalty mechanisms that	S.B. 137 (I)

		directly tie an electric utility's revenues to that utility's achievement on performance metrics.	
VA	Time-Varying Rates	H.B. 2547 requires Dominion Energy to convene a stakeholder group to provide recommendations related to the implementation of advanced metering technology and time-varying rates. The bill requires Dominion to file time-varying rate schedules by March 1, 2020. At least one schedule is not to include a demand charge. The bill also authorizes customer-generators to be served under these rate schedules. The Governor signed the bill into law in March 2019.	H.B. 2547 (E)

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

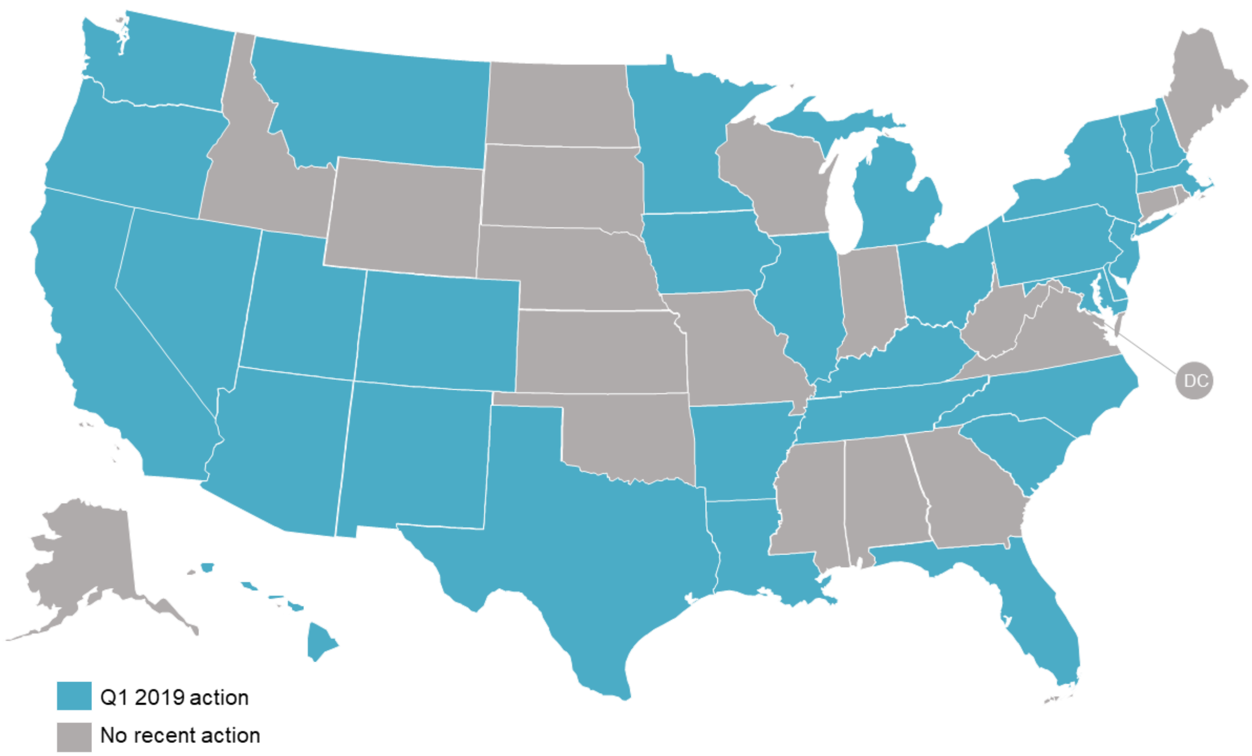
GRID MODERNIZATION POLICIES

Key Takeaways:

- In Q1 2019, 31 states took 104 actions on grid modernization policies, including energy storage targets, interconnection standards for energy storage, and rules related to advanced metering infrastructure.
- State legislatures considered 79 bills related to grid modernization policies, with 4 bills being enacted during Q1 2019 or early Q2 2019.
- Lawmakers in Montana and Utah enacted bills related to data access, while the North Carolina Utilities Commission opened a proceeding to develop data access rules.

States are considering many different ways to regulate and encourage the deployment of grid modernization technologies. In Q1 2019, 31 states took actions related to grid modernization policies, with the most common types of actions concerning data access policies and advanced metering infrastructure (AMI) rules. These policy questions are being addressed by both legislators and regulators, with at least 79 bills considered during quarter.

Figure 14. Action on Grid Modernization Policies (Q1 2019)



In Q1 2019, 19 states considered rules related to customer or third party access to AMI data. OhmConnect filed a complaint against Southern California Edison in March 2019 for its inability to supply the company with sufficient customer data. The North Carolina Utilities Commission opened a new proceeding in February 2019 to consider potential rules that would provide customers or a third party with appropriate access to customer data, while the Vermont Public Utility Commission approved a new data access standard. Legislation considered in at least nine states during the quarter addresses access to customer energy data, and bills were enacted in Montana and Utah. The Montana bill requires utilities to provide customers and third-party designees (upon a customer's request) with access to their own usage data. Utah's bill requires electrical corporations to provide non-residential customers with access to their energy usage data, but allows a fee to be charged for this access.

Box 4. A Note About Policies

Grid Modernization Policies is intended to be a broad category, capturing state-level policy actions related to grid modernization and the deployment of distributed energy resources (excluding solar-specific actions) that do not neatly fit into other categories in this report. The actions in this category are largely centered on market development policies, such as energy storage mandates, as well as regulatory procedures.

States also continue finding ways to integrate energy storage into existing policy frameworks. Legislation enacted in Arkansas allows net metering facilities to include energy storage devices that are configured to receive electricity solely from the net metering facility. Colorado is also examining the place for energy storage within its net metering rules in a new proceeding opened in February 2019. Three states (North Carolina, Oregon, and South Carolina) are examining the eligibility of energy storage under their Public Utility Regulatory Policies Act (PURPA) implementation rules. Other states considered interconnection rules for energy storage systems and the ability of renewable energy systems paired with energy storage to be used for renewable portfolio standard compliance.

Figure 15. Most Common Types of Policy Actions in Q1 2019

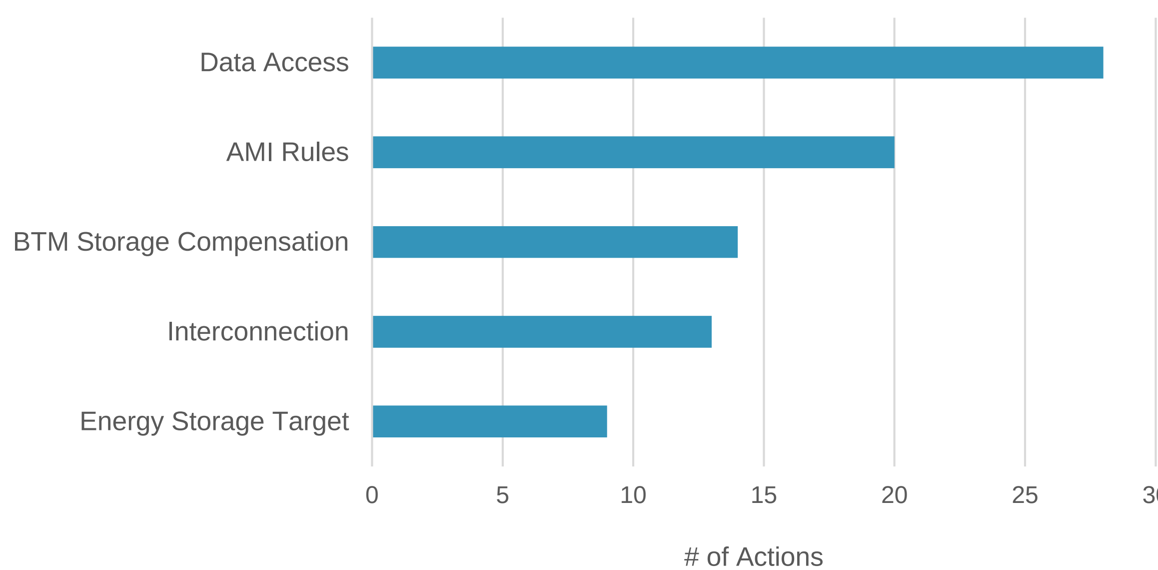


Table 5. Updates on Grid Modernization Policies (Q1 2019)

State	Policy Type	Description	Source
AR	Data Access	In November 2017, the Arkansas Public Service Commission expanded the scope of a generic proceeding on renewable distributed generation to more broadly consider policy changes related to distributed energy resources, as well as several specific data access questions. These data access issues and questions include identifying public policy goals that third-party aggregation and sharing of data with third parties may further, to what extent should AMI data that does not contain personal information be made available to certain entities, to what extent should AMI data that does not contain personal information be made available under privacy protections to entities wishing to provide AMI benefits to customers, identifying the potential costs and revenue-producing aspects of providing AMI data to third parties, and more. In July 2018, the Commission issued an order, establishing a list of issues to be addressed during the course of the proceeding, including third-party access to utility data, cybersecurity, confidentiality and privacy, and the process for customer consent to access data. The Commission accepted comments on the grouping of issues to be addressed in the proceeding and additional issues, the order and prioritization of these issues, means of addressing and building consensus on these issues, the expertise necessary to address these issues, and possible timeframes for events. The Commission will schedule an initial educational workshop on DER and grid modernization issues. The Commission also deferred action on the electric cooperatives' request for exemption from this proceeding until after the educational workshop.	Docket No. 16-028-U Order No. 10
	Energy Storage Compensation	S.B. 145, as amended, allows net metering facilities to include energy storage devices that are configured to receive electricity solely from the net metering facility. The bill specified that the capacity of the energy storage system is not to affect the project capacity for purposes of being under the maximum size limit. The Governor signed the bill into law in March 2019.	S.B. 145 (E)
AZ	Blockchain, Energy Storage Compensation, Energy Storage Target,	In August 2018, the Arizona Corporation Commission (ACC) opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules. Rules to be addressed in the proceeding include the renewable energy	Docket No. RU-00000A-18-0284

Interconnection, Renewable Portfolio Standard	standard, energy efficiency standards, resource planning and procurement, retail electric competition, net metering, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. A workshop to discuss retail electric competition was held in December 2018. In January 2019, the ACC published a policy statement on an alternative generation/buy-through program, which directs Arizona Public Service to expand and modify its current program to allow medium-sized commercial customers to participate or proposed a new program in its next rate case that would allow medium commercial customers to participate. The order also directs Tucson Electric Power and UNS Electric to propose an alternative generation/buy-through program for medium and large commercial and industrial customers in their next rate cases. The policy statement provides guidelines for the design of such a program. The ACC also adopted an electric vehicle policy statement in January 2019. In late January 2019, Commissioner Kennedy filed a letter suggesting that a proposal to increase the renewable energy standard to 50% by 2028 be considered at an upcoming workshop. Commissioner Kennedy also noted that she would like to see changes to net metering and more distributed solar and storage. In February 2019, Commissioner Kennedy filed another letter recommending a renewable energy standard of 50% by 2028 and the use of microgrids with distributed solar and energy storage. She also recommended restoring and expanding incentives for distributed solar, increasing the distributed energy carve-out and adding distributed storage equal to the distributed energy requirement. Following a stakeholder meeting in February 2019, the ACC Staff requested that parties provide written comments on modifications to the renewable energy standard and net metering rules, the necessity of the rules, and the potential combination of the ACC's energy rules, including which sections could be integrated. The Energy Storage Association proposed a storage deployment target, programs (including market-based solutions and incentives) to help achieve the target, and reforms to utility and grid planning rules. Tucson Electric Power and UNS suggested policies based on planning objectives, technology-neutral solutions, statewide energy	Policy Statement Regarding AG-Y Alternative Generation/Buy-Through Program

	goals that allow utilities to determine their contribution through the integrated resource planning process, allowing utilities to acquire non-renewable resources, and coordinating energy planning processes. Arizona Public Service suggested increasing the renewable energy standard, establishing a long-term clean energy goal, using compliance multipliers rather than mandates to encourage DG adoption, setting a cost cap on the renewable energy standard, and integrated rules with utility planning processes. Vote Solar supports an increased renewable energy standard and potentially an even larger clean energy requirement, as well as an increased DG carve-out and consideration of distributed storage. Tesla supports an energy storage target, and Sunrun recommends a solar-plus-storage carve-out, storage incentives, and 20-year export credit rate certainty for behind-the-meter solar-plus-storage systems. A second stakeholder workshop is scheduled for April 29, 2019. In February 2019, the ACC Staff filed a memo proposing that a workshop be held in April 2019 to review resource planning and procurement rules, a workshop be held in June 2019 to review blockchain technology, and a workshop be held in July 2019 to address retail electric competition. Meetings held in March 2019 addressed implementation of the electric vehicle policy statement, and oral proceedings held in March 2019 addressed the proposed interconnection rules. The ACC Staff filed a draft electric vehicle policy implementation plan in late March 2019.	
Clean Peak Standard, Energy Storage Target	In August 2016, Arizona Corporation Commission Chairman Little opened a docket to review, modernize, and expand Arizona's Renewable Energy Standard and Tariff. At the end of November, the Residential Utility Consumer Office filed a proposal to add a Clean Peak Standard to Arizona's RPS. The Clean Peak Standard would require a certain percentage of energy used to meet peak load hours to be derived from clean sources. In late January 2018, Commissioner Tobin filed his proposed Energy Modernization Plan. The proposed plan includes an energy storage target of 3,000 MW by 2030. The plan would also rename the state's Renewable Energy Standard and Tariff to the Clean Resource Energy Standard and Tariff and require that 80% of the state's electricity generating portfolio be	Docket No. E-00000Q-16-0289 RUCO Comments Proposed Energy Modernization Plan Notice of Inquiry Draft Rules

	comprised of clean resources by 2050. The proposal includes a Clean Peak Target, which will be based upon the current level of clean resources deployed during peak hours and increase by 1.5% on average each year until 2030. In early July 2018, Commissioner Tobin filed a formal set of draft rules implementing his proposed Energy Modernization Plan. Later in July, several Commissioners expressed support for opening a new rulemaking docket to consider changes to the state's Renewable Energy Standard and Commissioner Tobin's Energy Modernization Plan. In August 2018, the Commission opened a rulemaking docket to evaluate modifications to several different energy rules (see Docket No. RU-00000A-18-0284).	
Interconnection	Arizona is currently in the process of developing statewide interconnection rules (Arizona does not currently have statewide interconnection standards). In September 2017, the Arizona Corporation Commission Staff published a revised draft of the statewide interconnection rules, which includes new sections on energy storage system and advanced inverter requirements. The Staff requested comments on the draft rules, including in particular, the energy storage and advanced inverter requirements. The draft rules would not require non-exporting energy storage systems to comply with the requirements. Storage systems connecting directly to the utility's distribution system would be required to have the capability to operate in Power Factor Control mode, at any fixed reactive power output, and in Automatic Voltage Regulating mode. A stakeholder workshop was held in November 2017. In February 2018, Commissioner Tobin filed comments, recommending that the rules allow self-reporting with certification of technical compliance for non-exporting battery storage systems to satisfy interconnection requirements. The Commission Staff filed its proposed order in April 2018, which includes energy storage in each section of the rules. The proposed order would allow for inadvertent export from non-exporting energy storage systems under certain conditions and would allow non-exporting storage systems of 10 kW or less to go through an expedited interconnection process. In late November 2018, the Commission Staff filed a new memorandum and proposed order, superseding the one filed in April 2018. The newly revised rules would allow non-exporting inverter-based energy storage systems and inadvertent exporting systems of 20	Docket No. RE-00000A-07-0609 Revised Draft Rules Proposed Order Proposed Order (Nov. 2018)

		kW or less to go through an expedited interconnection process. The Staff recommend that a rulemaking docket be opened and notice of proposed rulemaking issued by February 2019. In December 2018, the Staff filed proposed revisions, which would remove unnecessary screening requirements for non-exporting systems and amend language related to advanced inverter standards. Commissioner Tobin and Commissioner Olson filed proposed amendments related to energy storage in December as well. The Commission issued a decision in January 2019, directing the Utilities Division to open a rulemaking docket. Tucson Electric Power, UNS Electric, the Solar Energy Industries Association, and Western Resource Advocates filed comments in support of the proposed rules. Sunrun also filed comments in support of the rules, but suggested that non-exporting storage systems should be permitted to interconnect through an expedited permitting process requiring only notification to the utility. Sonnen and Tesla also filed comments in support of the rules, but suggested modifications to the definition of "maximum capacity" so that it reflects systems' operating characteristics and not only nameplate capacity.	
CA	Data Access	OhmConnect filed a complaint against Southern California Edison in March 2019. OhmConnect is a third-party demand response provider that provides demand response services to Southern California Edison and the broader electric grid through arrangements with approximately 40,000 residential and small commercial retail electric customers of the utility. OhmConnect can use the aggregated load reductions of its customers to bid its collective resource adequacy capacity into the CAISO market. In its complaint, OhmConnect argues that Southern California Edison has demonstrated a pattern of misconduct and an unwillingness to devote the technical resources necessary to properly share the necessary customer data with them. The Commission filed an Instructions to Answer Notice in March 2019. Southern California Edison must provide a written response to the complaint within 30 days.	Docket No. C-19-03-005
	Demand Response	In January 2017, the state's three major IOUs submitted applications for their 2018-2022 demand response budgets and programs. The California Public Utilities Commission approved the budgets and programs in December 2017, but left the proceeding open to address several	Docket No. A-17-01-012 Amended Scoping Ruling

unresolved policy matters. The demand response programs approved by the Commission included an auction mechanism pilot, which is still being assessed. Other issues this proceeding is continuing to explore are pilots for promoting demand response in disadvantaged communities and transmission constrained local capacity areas, a new automated demand response incentive policy, the demand response Capacity Bidding Program, and the demand response Two Percent Reliability Cap. An amended scoping memo filed in May 2018 officially added these issues to the proceeding and extended the deadline for the proceeding to July 17, 2019. The Commission's Energy Division hosted a workshop to present interim results of the demand response auction mechanism pilot evaluation in July 2018 and followed up with a series of seven questions for intervenors. A decision filed in late November 2018 resolved the remaining issues and declined to authorize additional demand response auction mechanism pilot solicitations. The Commission also filed a ruling in November 2018, scheduling a prehearing conference for mid-January 2019 to discuss the filings by the utilities for the FERC Tariff Amendment to Implement Energy Storage and Distributed Energy Resources Requirements, and to discuss next steps for determining demand response baselines. A ruling issued in January 2019 established two working groups: one to propose improvements for performance and accountability and one to propose improvements to the demand response auction mechanism pro forma contracts. Both working groups met in January 2019 and were scheduled to develop draft proposals in February 2019. Additional workshops were held in February 2019 during which the participants discussed the following matters related to the Auction Mechanism: (1) a goal for the Auction Mechanism; (2) objectives for the Auction Mechanism; (3) proposals to ensure Qualifying Capacity; (4) proposals to improve performance; (5) proposals to ensure accuracy of demonstrated capacity invoicing; (6) proposals for contract improvements; and (7) whether the Auction Mechanism should have an energy component to increase dispatch hours. Another ruling issued in February 2019 presented a series of 23 questions and asked the participants to file responses in March. A technical workshop was held in March 2019 to discuss the baselines to be used in the demand response programs.

Energy Storage Compensation	A January 2016 decision from the California Public Utilities Commission (CPUC) established a successor tariff to replace net metering when the utilities reach their aggregate caps. Part of this discussion has included net metering options for PV systems paired with energy storage. In August 2017, the utilities filed a petition for modification of an April 2016 decision that established a net metering bill credit estimation methodology for generating facilities paired with storage. The original methodology required the utilities to perform a customer-specific estimation using a calculator developed for the California Solar Initiative. The utilities instead asked to use a single kWh per-kW profile for each climate zone. Decision No. 18-02-008 of February 2018 granted the utilities their petition for modification. A proposed decision issued in August 2018 addressed a petition for modification of a previous decision to modify the definition of "small" net metering systems paired with energy storage from less than or equal to 10 kW, to less than or equal to 30 kW. The proposed decision denies the petition. A proposed decision issued in late December 2018 sets the requirements for equipment for larger DC-coupled systems; these systems will be able to net meter if they install power control equipment to prevent storage systems from charging from or exporting to the grid. An earlier proposed decision would have allowed the use of an ex post data verification option, which is not allowed in this decision. In January 2019, the CPUC issued a decision partially granting a petition for modification filed by the California Solar and Storage Association (formerly the California Solar Energy Industries Association) in September 2017 regarding the ability of solar-plus-storage systems to export solar-generated electricity from the storage system. The decision approved non-metering, power control-based options for ensuring net metering credits accrue only the net metering-eligible generation, as long as the control configuration is certified to a national standard or a utility-approved interim testing procedure. A ruling issued in March 2019 solicited comments on enhanced consumer protection measures for net metering customers and briefs on parties' positions regarding the authority of the CPUC over third-party solar providers. Comments were due in March 2019, and briefs were due April 12, 2019.	Docket No. R14-07-002 Decision No. 18-10-005 (Denial of modification of small NEM paired with storage)

	Energy Storage Compensation, Interconnection	S.B. 288 requires the California Public Utilities Commission (CPUC) and municipal utilities to create one or more tariffs that offer fair compensation for customer-sited energy storage systems by January 1, 2021. The bill also requires the CPUC to collaborate with the California ISO to modify existing tariffs to remove barriers to the participation of customer-sited energy resources in programs intended to provide energy, capacity, and ancillary services for the bulk power system. The bill further requires the CPUC and California Energy Commission to establish a streamlined and standardized process for reviewing interconnection requests for solar-plus-storage systems.	S.B. 288 (I)
	Energy Storage Target	S.B. 772 requires the California ISO, on or before June 30, 2022, to complete a competitive solicitation process for the procurement of one or more long duration energy storage projects that in aggregate have between 2,000 MW and 4,000 MW capacity.	S.B. 772 (I)
	Microgrid Compensation	A.B. 1503, as originally introduced, would have repealed language directing the Commission to take actions to facilitate the commercialization of microgrids for distributed customers. These provisions were originally enacted in 2018. The amended version no longer repeals these provisions.	A.B. 1503 (Relevant provisions amended out)
CO	Energy Storage Compensation, Interconnection	On February 27, 2019, the Colorado Public Utilities Commission opened a rulemaking docket with proposed changes to electric resource planning (ERP), renewable energy standard, net metering, community solar, PURPA, and interconnection rules. This follows last year's stakeholder proceeding (Docket No. 17M-0694E) on these issues. New net metering rules would include language establishing the eligibility of energy storage paired with generation for net metering, and would establish rules for net metering for customers on TOU rates. New interconnection rules change the definition of a "small generating facility" into a definition for a "distributed energy resource," which includes energy storage. The rules also allow for a single interconnection request to be made for generation facilities paired with energy storage. Parties filed their initial comments in March 2019. Xcel Energy generally supported the proposed rule changes, but opposed creating a prohibition on establishing a separate rate class for net metering customers. Solar industry	Docket No. 19R-0096E

		parties commented that proposed rules requiring "bucketing" under time-of-use rates for some customers might devalue solar investments and that the proposed interconnection rules do not go far enough in meeting statutory goals to limit barriers for customer-sited energy storage.	
DE	Energy Storage Cost Recovery	H.B. 95 allows electric cooperatives to use unclaimed capital credits to fund, among other things, battery storage projects.	H.B. 95 (I)
FL	AMI Rules	In January 2019, Tampa Electric Company filed a petition for approval of a smart meter opt-out tariff. Customers opting out of AMI installation would be required to pay a $96.27 one-time fee and a $20.64 monthly fee. The Commission approved the proposed tariff in early March 2019.	Docket No. 20190024 Order No. PSC-2019-0112-TRF-EI
	Data Access	H.B. 591 and S.B. 600 exempt customer meter-derived data from public records requirements, which municipal utilities in the state are subject to.	H.B. 591 (P1) S.B. 600 (I)
HI	Data Access	S.B. 1442 charges the Public Utilities Commission with enabling ratepayers to access their energy consumption and production data; enabling ratepayers to authorize third-party data access and allow verification of third-party authorization through electronic signature; increasing the amount of publicly-available data related to utility generation, transmission, and distribution systems, as well as non-utility data from third parties that provide generation or non-wire alternatives to individual customers or the grid; and ensuring that electric power systems data is made available through simple, electronic, consistent, machine-readable formats with temporal and geographic granularity. The Senate passed the bill in March 2019. The House amended the bill and passed in April 2019. The Senate disagreed with the House amendments, and a Conference Committee recommended the bill be passed with amendments.	S.B. 1442 (P1)
	Data Access	A March 2019 order approved Phase 1 of HECO's grid modernization plan, which includes components that will enable both customers and customer-authorized third parties to access customer data through a customer energy portal that includes Green Button functionality for customers and customer-authorized third parties to access advanced meter data. The order additionally directed the utilities to develop a	Docket No. 2018-0141 Order

		Data Access and Privacy Policy, describing the utilities' planned data access efforts and the expected timeline for implementation. The Policy Plan must also explore the expenditures and time required to extend Green Button Connect and Download My Data functionality to all customers, including those without advanced meters; and include information on the data sets to be offered to customers, the utilities' data hosting policies, and third-party data access and data availability.	
	Interconnection, Microgrid Compensation	H.B. 2110, enacted in July 2018, requires the Public Utilities Commission to open a proceeding by July 1, 2018 to establish a microgrid services tariff designed to provide fair compensation for electricity, grid services, and other benefits. The Commission opened a proceeding in July 2018 to develop the microgrid services tariff. A January 2019 order provided additional guidance for answering the Commission's preliminary questions in opening briefs. Opening briefs, filed in February 2019, addressed eight preliminary questions: (1) how to define the term microgrid, (2) what microgrid characteristics to include in the definition, (3) what ownership structures should be included in the microgrid services tariff, (4) what microgrid services or functions should be considered in designing the tariff, (5) if a microgrid owner/operator should be required to provide a minimum set of services, (6) how existing tariffs and programs should be coordinated with the microgrid services tariff, (7) how interconnection standards and procedures should be modified, and (8) any other considerations. Parties filed reply briefs in March 2019.	Docket No. 2018-0163 H.B. 2110 (2018)
	Microgrid Permitting	H.B. 72 requires microgrid owners and operators to file an application for a microgrid certificate of public convenience and necessity. The Public Utilities Commission is to adopt rules establishing minimum standards to receive such a certificate.	H.B. 72 (I)
IA	AMI Rules	H.F. 154 and S.F. 233 require utilities to allow customers to refuse installation of a digital or smart meter, require utilities to replace digital or smart meters upon customer request, and prohibit utilities from offering discounts for customers that install digital or smart meters or charging higher fees or rates to customers that elect to not install digital or smart meters.	H.F. 154 (I) S.F. 233 (I)

AMI Rules	In January 2018, the Iowa Utilities Board sent a letter to Interstate Power & Light Company (IPL) requesting a response to customer complaints about installation of advanced meters, specifically asking whether customers are allowed to opt out of installation, whether installed meters are fully functional, and whether IPL would remove an advanced meter if a customer's health is affected by it in the view of a medical professional. In February 2018, IPL filed a response laying out its planned opt out provision, explaining that meters would become fully functional once all communication infrastructure is installed no later than September 2019, and explaining that advice from a medical professional would not entitle customers who would otherwise be unable to opt out (i.e. those who self-generate or are on time-of-use rates) to opt out (the standard opt-out provision would be available to everyone not in those categories). In March 2018, IPL filed a proposed tariff for residential customers that would charge a $15 monthly fee to any customers who opt out of having a smart meter installed. Customers who opted out would also need to provide a monthly manual meter reading to the utility. In July 2018, the Utilities Board merged this proceeding and the proceeding regarding customer complaints (Docket No. C-2018-0006) into one "master" docket (Docket No. SPU-2018-0007). The Utilities Board issued a final order in February 2019, rejecting IPL's proposed tariff and directing IPL to file a revised tariff that allows customers to opt out of AMI installation on a permanent basis, allows all residential customers on the general residential rate to opt out of AMI installation, allows customers to opt out without any fee, allows customers with analog meters to retain them, provides a choice of a non-transmitting digital meter or an AMI meter set to pulse only once a month for customers electing to opt out, and uses twice-per-year actual reads with estimated bills for remaining months for calculating bills for customers with analog or non-transmitting digital meters. Several parties filed rehearing requests in late February 2019. In March 2019, the Office of the Consumer Advocate (OCA) filed a request for a temporary cessation of AMI installation, which would last until revised tariffs consistent with the final order are filed. Multiple parties filed responses both in support of and in opposition to this request. Later in March, the Board granted the rehearing	Docket No. C-2018-0006 Docket No. TF-2018-0029 Docket No. SPU-2018-0007

		requests to allow for further review, requiring IPL to file compliance tariffs despite the rehearing, and denying the request for a temporary cessation of AMI installation, but ordering IPL to meet with the OCA to discuss any meter installations that may be out of compliance with earlier Board orders. IPL filed additional testimony in early April 2019, as well as compliance tariffs.	
	Energy Storage	H.F. 346 adds new in-state solar energy purchase requirements for Iowa utilities and allows energy storage capacity paired with solar energy to count towards the required solar energy capacity.	H.F. 346 (I)
IL	Data Access	In March 2017, the Illinois Commerce Commission opened a docket to investigate the creation of a third-party warrant process for access to customer AMI data. The issue had earlier been dismissed from Docket No. 14-0507 for consideration in a separate docket. Two motions to dismiss the proceeding were filed in October 2017 (one by the Illinois Attorney General, another by the Illinois Competitive Energy Association). These motions would result in no third-party warrant process being created. The motions were denied in May 2018. Parties filed reply comments in December 2018 and final comments in January 2019.	Docket No. 17-0123
	Demand Response	H.B. 2956 removes the exemption of customers of certain utilities from demand response deployment requirements. Illinois law currently requires utilities to deploy cost-effective demand response measures to reduce peak demand for retail customers by 0.1% over the previous year. However, this requirement does not apply to utilities with more than 500,000 customers and a maximum 15-minute demand of more than 10,000 kW. This bill would remove the exemption for larger utilities.	H.B. 2956 (I)
	Energy Storage Compensation, Interconnection	H.B. 2966 includes co-located energy storage systems in the definition of community renewable generation and net metering projects and requires the Corporation Commission to update interconnection standards so as to facilitate energy storage systems.	H.B. 2966 (I)
KY	Energy Storage Compensation	An amendment to S.B. 100 would have allowed energy storage systems to be incorporated into net metering facilities. The amendment was withdrawn and the bill passed in March 2019.	S.B. 100 (Relevant provisions amended out)

		The Governor signed the bill into law later in March.	
LA	Data Access	In June 2018, the New Orleans City Council opened a rulemaking proceeding to consider revising the city's customer service regulations to allow Entergy New Orleans to disclose whole-building energy use data to owners of buildings with four or more meters without first obtaining authorization from tenants. The Council accepted comments on this topic, as well as mapping meters to buildings and automating data aggregation and transmission. The City Council's Utility Advisors filed a report with recommendations in October 2018. The Advisors recommend that only whole-building data be released and that data for a subgroup within a building should not be released. The Advisors recommend that these buildings must have at least four active meters and at least four unique customers to allow data to be released. Data would be released to only building owners or an owner's designated representative upon request. In December 2018, the City Council adopted a resolution and order revising customer service regulations to allow the release of aggregated whole-building data to building owners under certain conditions. The resolution directs Entergy New Orleans to file draft processes for the release of whole-building data and further information on the costs and benefits to ratepayers of releasing this data prior to the full implementation of AMI. In mid-February 2019, Entergy filed its draft process for release of whole-building data. In March 2019, Entergy requested an extension of time to file its proposed interim solution.	City Council Docket No. 18-04 Advisors' Report Resolution No. R-18-539
MA	AMI Rules	S. 1988 requires that utilities provide customers with a choice of the type of meter to be installed and operated on their property and that customers have the option of using an electrochemical analog meter. Utilities are to provide customers with the option of having a smart meter replaced with a non-transmitting meter at no cost.	S. 1988 (I)
	Clean Peak Standard	The Department of Energy Resources (DOER) is developing rules to implement Chapter 227 of the Acts of 2018, which adopted a clean peak standard for the state. In December 2018, DOER determined that approximately 0 MWh are currently being served by existing clean peak resources during peak load hours and set the minimum standard percentage requirement for	Massachusetts Clean Peak Standard Straw Proposal

	the 2019 compliance year at 0%. In January 2019, DOER released draft questions to receive stakeholder feedback on. Many of the questions relate to which types of resources should be eligible for compliance, how the seasonal peak periods should be established, and how compliance should be handled. Responses to the questions were filed by stakeholders in February 2019. In early April 2019, DOER presented its straw proposal for the clean peak standard. The proposal includes four types of eligible resources: (1) new Renewable Portfolio Standard (RPS) Class I resources, (2) existing RPS Class I or II resources that are paired with energy storage systems, (3) standalone energy storage systems and incremental pumped storage capacity, and (4) demand response resources. Compliance with the standard will be demonstrated with Clean Peak Certificates (CPCs) generated by eligible resources during seasonal peak periods. DOER proposed four hours per day for each season as designated seasonal peak periods. These hours are Winter - 8am to 9am and 4pm to 7pm; Spring - 8am to 9am and 5pm to 8pm; Summer - 2pm to 6pm; and Fall - 8am to 9am and 4pm to 7pm. CPCs will be generated according to the average output of the resource over the duration of the day's seasonal peak period. The straw proposal also includes multipliers based on season, actual monthly system peak, resilience, minimum load (negative multiplier), and distribution circuit locational value. DOER is also considering a tariff mechanism to procure CDCs. DOER will develop an alternative compliance payment designed to meet market need and plans to keep this payment rate level for the first 10 years. Comments on the straw proposal were accepted until April 12, 2019.	
Clean Peak Standard	H. 2884 amends the definition of qualified energy storage system so that it does not have to have commenced commercial operation on or after January 1, 2019. This would allow storage systems operating before 2019 to be used for compliance with the new clean peak standard under development.	H. 2884 (I)
Energy Storage Compensation	In October 2017, the Department of Public Utilities (DPU) opened an inquiry into the net metering eligibility of solar plus storage systems (or energy storage paired with other types of eligible net metering systems), as well as the	Docket No. 17-146

eligibility of net metering facilities to participate in the Forward Capacity Market. Comments and reply comments were accepted on six questions related to storage eligibility: (1) Should energy storage systems be allowed to net meter? (2) Should only certain types of energy storage systems be allowed to net meter? (3) What technical requirements would be necessary so that the storage system and net metering facility can both participate in the ISO New England energy and capacity markets? (4) What process could ensure that the storage system is only charged by the net metering facility and does not export power to the grid? (5) What other requirements would be necessary to safeguard against gaming and manipulation of net metering rules? (6) Should the net metering cap allocation reflect the combined capacity of the net metering facility and storage system, and should there be a distinction between existing and new net metering facilities? A technical conference was held in late January 2018. A technical conference on the eligibility of net metering facilities to participate in the Forward Capacity Market was held in June 2018, following the release of a straw proposal from the DPU Staff. Following the conference, the Staff published a revised straw proposal and solicited comments on several questions, including if a host customer or SMART project owner should have sole authority to assert title to an energy storage system's capacity rights and if the DPU should treat a storage system's capacity differently than the capacity of a net metering SMART program facility it is co-located with. The DPU also requested comments on a definition for inadvertent export to the electric distribution system, and what types of configurations could experience this.

The DPU issued an order in February 2019, authorizing solar-plus-storage systems to net meter under the three following configurations: (1) the storage system charges only from the net metering facility and cannot export, (2) the storage system charges only from the net metering facility and can export, and (3) the storage system charges from either the grid or the net metering facility and cannot export. The order also establishes other requirements for these systems to net meter. The DPU also issued an order in February 2019 deciding that capacity rights of Class II and III net metering facilities transfer the utility when enrolled in net metering and that the utility is obligated to

	participate in the forward capacity market with the facilities. The utility will not have capacity rights for Class I net metering facilities, small hydro projects, or energy storage paired with net metering facilities. The order also declares that the capacity rights of systems participating in the SMART program's Alternative On-Bill Credit mechanism transfer to the utility. The order directs the utilities to file revised net metering and SMART tariffs. In February 2019, parties filed comments on whether the load reducer option provides enough indirect benefits to ratepayers to outweigh the direct benefits ratepayers of the utilities participating in the ISO-NE energy and capacity markets with all behind-the-meter Class II and III net metering facilities.	
Energy Storage Target	H. 2802 and S. 2005 direct the Department of Energy Resources to establish an energy storage target of 2,000 MW by 2030 and a subsequent target to be achieved by 2035. Utilities may not own or operate more than 20% of this capacity. The Department is also to establish a carve-out within the alternative energy portfolio standard for energy storage systems.	H.2802 (I) S. 2005 (I)
Energy Storage Target	H. 2862 directs IOUs to procure energy storage resources through competitive solicitations. The utilities are to enter into long-term contracts for 4,745 GWh of nameplate capacity, with 2,372.5 GWh coming from existing energy storage peak renewable power and the additional 2,372.5 GWh coming from new energy storage peak renewable power. The timetable and procurement methods are to be jointly proposed by the utilities and the Department of Energy Resources.	H. 2862 (I)
Energy Storage Target	S. 2008 establishes a statewide energy storage target of 2,000 MW by 2030, and directs the Department of Energy Resources to develop a subsequent target to be achieved by 2035. The Department would establish annual targets for each of the state's distribution companies and municipal lighting plants. The bill limits distribution companies to owning or operating no more than 20% of the annual target. The Department can consider a variety of deployment mechanisms and policies to help achieve this target. Distribution companies and municipal lighting plants are also required to make a map available each year that shows areas of critical need for storage systems. The bill also directs the Department to establish a	S. 2008 (I)

		carve-out in the existing alternative energy portfolio standard for energy storage systems.	
	Interconnection	H. 3667 prevents any customer from being denied the ability to interconnect a DG facility, energy storage system, or paired DG and storage system. The bill sets out rules for DG and storage interconnection related to timeframe and fees. The bill also creates a working group to consider improvements to the interconnection tariffs.	H. 3667 (I)
	Permitting	In January 2019, Cranberry Point Energy Storage, LLC petitioned the Energy Facilities Siting Board for a determination that the Board does not have jurisdiction over the company's planned energy storage project because it will store energy, rather than generate energy. The Siting Board has authority over "generating facilities." Eversource, National Grid, and RENEW Northeast filed comments on the petition in February 2019. Eversource recommended that the Siting Board make a determination that large-scale energy storage projects are under the Board's jurisdiction when they are operating to provide a "source" of electricity with the intention of selling the electricity at wholesale. National Grid and RENEW Northeast concluded that energy storage systems are not subject to Siting Board jurisdiction.	Docket No. EFSB19-01
MD	Data Access	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. A working group to examine Competitive Markets and Customer Choice was established as part of this process, and in late June 2017, the group filed a request to seek comments and hold a hearing to support the development of regulations pertaining to customer interval data access. In January 2018, the Competitive Markets and Customer Choice working group recommended that the PSC initiate a rulemaking proceeding to consider the group's proposed Phase II regulations (related to instant connects and seamless moves). The group also recommended that the PSC address the proposed data access regulations filed in June 2017, which remain substantively unchanged. The Commission agreed and opened Rulemaking 62 in March 2018, and	Public Conference No. 44 Rulemaking No. 62

		accepted comments through April 2018. The Commission held rulemaking sessions in May and August 2018, as well as February 2019.	
	Interconnection	In December 2017, the Maryland Public Service Commission initiated a rulemaking proceeding to consider revisions to the state's small generation interconnection process, as recommended by stakeholders in the Public Conference 44 Interconnection Working Group. The working group reached consensus on making the interconnection process more efficient, allowing applications to be filed electronically, removing monitoring for systems less than 2 MW, and other improvements. The proposed regulations include (1) the addition of energy storage provisions, (2) amendments to the interconnection process for systems larger than 25 kW and less than 2 MW, as well as a number of other minor changes. Rulemaking sessions were held in January, April, and September 2018.	Public Conference No. 44 Rulemaking No. 61
MI	AMI Rules	In September 2018, as part of a general rate case, Upper Peninsula Power Company (UPPCO) proposed deploying AMI for all of its residential and small commercial customers. There will be an opt-out process for customers who do not wish to have an advanced meter installed; customers opting out would need to pay a $14.26 monthly meter-reading fee, and customers who opt out after an advanced meter is already installed will also need to pay a $62.25 one-time fee to exchange their meter. In testimony filed in February 2019, Michigan Public Service Commission Staff recommended against allowing cost recovery for the AMI investment due to concerns about the bill impact for ratepayers. A final order is expected in August 2019.	Docket No. U-20276
	Data Access	In December 2017, the Michigan Public Service Commission (PSC) opened a proceeding to process data privacy tariffs utilities are required to file under the newly promulgated Michigan Administrative Code R460.153. All utilities filed data privacy tariffs during Q2 2018. The Commission requested that the utilities file revised tariffs to ensure that the tariffs contain clear instructions for how a customer (or authorized third party) could access their usage data. All utilities filed revised tariffs in July and August 2018. In late October 2018, the PSC issued an order approving the tariffs filed by all utilities except the tariff from DTE Energy; the	Docket No. U-18485 Michigan Administrative Code

		PSC was concerned that DTE's data access system would not allow authorized third parties to access usage data independently (the customer would need to send the data to the third party), and directed DTE to file an updated tariff by December 14, 2018. The PSC also directed Commission Staff to convene a forum of interested parties to discuss developing more refined, clear, and consistent language addressing data privacy and data accessibility. DTE filed its revised data privacy tariff in December 2018. In January 2019, the PSC issued an order approving DTE's updated tariff. A report of findings and recommendations from the forum was filed in April 2019.	
	Interconnection	In November 2018, the Michigan Public Service Commission opened this docket to conduct an investigation of interconnection rules, legally enforceable obligations under PURPA, distributed generation (including energy storage), and legacy net metering rules. The interconnection working group met in early December 2018, and stakeholder meetings for each of the different subjects took place in January 2019. The interconnection working group met in February 2019, and all three working groups met in March 2019.	Docket No. U-20344
MN	Data Access	H.B. 1683, H.B. 2681, and S.B. 2054 require utilities to provide customers with access to their own energy use data. The utility must also grant data access to a third party if the customer authorizes it. A utility must also prepare and make available summary energy usage data upon the written request of any person.	H.B. 1683 (I) H.B. 2681 (I) S.B. 2054 (I)
	Data Access	H.B. 1833 and S.B. 2067 require utilities to provide customers with access to their own energy use data. The utility must also grant data access to a third party if the customer authorizes it. A utility must also prepare and make available summary energy usage data upon the written request of any person.	H.B. 1833 (I) S.B. 2067 (I)
	Energy Storage Cost Recovery	H.B. 165 and S.B. 100 authorize utilities to undertake energy storage pilot projects and establish criteria for utilities to recover costs for investment in energy storage pilot projects.	H.B. 165 (I) S.B. 100 (P1)
	Energy Storage Cost Recovery	H.B. 1165 and S.B. 1608 establish criteria under which utilities could recover costs for investment in energy storage pilot projects and establish some criteria under which the Commission should consider storage as a resource.	H.B. 1165 (I) S.B. 1608 (I)

	Interconnection	The Minnesota Public Utilities Commission has an open proceeding to update the state's interconnection standards. The Commission opened a comment period in February 2018 to receive input on the Commission Staff's recommended updates to the interconnection standards. The updated standards are based on FERC's Small Generation Interconnection Procedures, and includes provisions to allow energy storage, both connected to a small generator, and as a standalone device. The Commission held a meeting in May 2018 to receive input on the staff proposal, and approved the new standards in August 2018. Some issues were left unresolved by the August order, and the DG working group met again in November 2018 to resolve the remaining issues. An updated draft of the interconnection standards was released in late November 2018. Parties filed comments throughout Q1 2019.	Docket No. 16-521 Order
MT	AMI Rules, Data Access	H.B. 267 defines advanced metering device and requires utilities to secure and not disclose energy use data from advanced metering devices. The bill requires customers to be notified prior to AMI installation and directs the Public Service Commission to determine whether an AMI opt-out program should be established by July 2020. The House passed an amended version of the bill in February 2019. The amended version allows utilities to disclose aggregated energy use data that is anonymous and makes energy use data collected by AMI available to the customer or to a customer's designee, upon request.	H.B. 267 (E)
	Demand Response	H.B. 568 establishes an energy efficiency standard, which may be achieved with demand response, smart grid technologies, energy efficiency improvements, and software enhancements. The bill was withdrawn in March 2019.	H.B. 568 (D)
	Energy Storage Cost Recovery	H.J.R. 19 is a resolve that encourage the Public Service Commission to look favorably upon utility ownership of energy storage projects to meet community renewable energy project obligations.	H.J.R. 19 (D)
NC	AMI Rules, Data Access	The North Carolina Utilities Commission opened a proceeding in August 2017 to update its rules related to the location, testing facilities, average error calculations and accuracy of electric meters. This proceeding overlaps with and is dependent upon other open proceedings related to AMI. In November 2018, the Commission	Docket No. E-100 Sub 153

	issued an order scheduling a staff technical conference and a tour of the meter testing facilities of Duke Energy Carolinas. The order also required all three electric utilities to file information describing their current meter testing programs. The technical conference was held in December 2018, and Duke was unable to answer some of the questions raised. In January 2019, the Public Staff proposed in comments filed in Docket No. E-100 Sub 157 that the rules being developed in this proceeding (E-100 Sub 153) could be updated to include data access rules. In February 2019, the Commission opened a new rulemaking (Docket No. E-100 Sub 161) to separate and address the data access issues raised in this proceeding and in Docket No. E-100 Sub 157. The Commission filed an order in February 2019 formally requesting responses to the questions raised during the technical conference. The utilities later filed their responses.	
Data Access	The North Carolina Utilities Commission opened a new proceeding in early February 2019 to investigate various metering issues that were raised in other proceedings. One of the issues to be examined in this new proceeding is potential rules that would provide customers or a third party appropriate access to customer data, while protecting customers and their personal and energy consumption data. Duke Energy and Dominion are to file responses to three questions about metering standards by March 1, 2019. The utilities are also to respond to customer comments regarding AMI meters resulting in "dirty electricity" or harmonic distortions. Initial comments and proposed rules were initially due by April 15, 2019, but was extended to June 14, 2019.	Docket No. E-100 Sub 161
Interconnection	Following the adoption of revised interconnection standards in 2015, the North Carolina Utilities Commission (NCUC) directed the Public Staff to convene stakeholders in two years to discuss the functioning of the new standards. Advanced Energy, the entity assigned by the Public Staff to facilitate the stakeholder process created four working groups during Q2 2017. One of the working groups is examining new technologies, including energy storage. The working groups held multiple stakeholder meetings, and the Public Staff submitted its report to the NCUC in December 2017. The Public Staff stated that no consensus was reached regarding what revisions should be made to the interconnection	Docket No. E-1 Sub 101 Joint Proposed Order

	standard. A redlined version of the standard was included with comments and proposals from all participants identified. The NCUC issued an order in December 2017 calling for all parties to submit initial comments. Parties filed comments during Q1 2018, with all parties agreeing on allowing the interconnection rules to apply to energy storage. An October 2018 order approved interim modifications to the interconnection procedures to accommodate Tranche 1 of the Competitive Procurement RFP, and established that further changes will be considered via testimony in November and December 2018, followed by an evidentiary hearing in January 2019. The interim modifications do not reference energy storage. A stipulation and partial settlement between Duke Energy and the Public Staff filed in late January 2019 includes proposed changes to the interconnection rules. The proposed rules include storage as an eligible technology. The utilities and the Public Staff filed a joint proposed order in March 2019, which would approve the proposed rule changes.	
PURPA Rules	H.B. 589 of 2017 requires Duke Energy to procure 2,660 MW of renewable energy through a competitive procurement program occurring through four solicitations over a 45-month period. The competitive procurement program is the state's new PURPA implementation mechanism. A February 2018 order from the North Carolina Utilities Commission (NCUC) approved the joint program proposed by Duke Energy Carolinas and Duke Energy Progress, as well as the use of Duke's proposed pro forma purchase power agreement (PPA) in the Tranche 1 solicitation. Duke Energy filed a revised pro forma PPA in May 2018, which included new requirements for energy storage projects that were not included in the original. The North Carolina Sustainable Energy Association and the North Carolina Clean Energy Business Alliance filed a joint motion requesting that the Commission require Duke to remove all of the recently added energy storage provisions until there is stakeholder consensus and approval from the Commission. A June 2018 order from the Commission denied the joint motion and approved the revised pro forma PPA. The first solicitation will be going forward with the energy storage requirements in place, but a motion for clarification was filed in July 2018 for the Commission to confirm that the energy storage provisions will not automatically be included in the pro forma PPA for future	Docket No. E-7 Sub 1156 Docket No. E-2 Sub 1159 Pro Forma PPA Tranche 1 Order

		tranches. A July 2018 order confirmed that Duke will need to refile its pro forma PPA for each future tranche, and that the energy storage provisions can be reconsidered in them. The Commission issued another order in October 2018 addressing changes to the interconnection procedures as they relate to the competitive bidding process. A solar developer filed a motion to stay the effectiveness of a portion of the Commission's decision, which the Commission granted in November 2018. The stay made no mention of the Commission's rulings related to storage. In December 2018, the Commission issued an order directing Duke Energy to file a status report and results from the Tranche 1 solicitation and authorized the utilities to implement the program plans and open the Tranche 2 solicitation in July 2019. Parties filed comments during Q1 2019.	
NH	Data Access	S.B. 78 adds researching, developing, and implementing new rate structures and tariffs to the list of eligible purposes for service providers collecting and using customer electric data. The Senate passed the bill in March 2019.	S.B. 78 (P1)
	Data Access	S.B. 284 establishes a statewide, multi-use online energy data platform to be administered by the Public Utilities Commission. The platform will allow for customer access to energy usage data, as well as access for third parties with permission.	S.B. 284 (P1)
	Energy Storage Compensation	S.B. 13 adds energy storage systems to the definition of customer-generator, allowing storage and generating facilities plus storage to net meter. The bill increases the eligible system size limit for net metering from 1 MW to 5 MW.	S.B. 13 (I)
	Energy Storage Cost Recovery, Interconnection	S.B. 204 creates a definition for energy storage system and states that energy storage shall not be considered electric generation. By adding energy storage to the definition of DERs, the bill allows utilities to seek rate recovery for investments in DERs. The bill directs the Public Utilities Commission to adopt rules allowing the installation, interconnection, and use of energy storage systems by utility customers. The rules are to ensure consumers have a right to install and use storage systems without unnecessary restrictions or discriminatory rates and fees. The bill prohibits utilities from requiring a separate meter in addition to a single net energy meter for customer-sited storage systems. The Senate passed an amended version of the bill in March	S.B. 204 (P1)

		2019. The amended bill no longer includes the provision that energy storage shall not be considered electric generation.	
	Energy Storage Compensation, Energy Storage Target	H.B. 715 tasks the Public Utilities Commission with ensuring that enough energy storage capacity is deployed to reduce peak demand by 2% (when discharging coincidentally) by December 31, 2022. The Commission is to create programs and tariffs to enable energy storage to be compensated for the services it provides. Within one year of the effective date of the legislation, the Commission is to initiate a proceeding to determine if a higher energy storage target would provide net benefits to ratepayers. If the Commission determines a higher target would provide net benefits, it is to increase the target up to 15% of peak demand by December 31, 2030. Non-utilities are to own at least half of the storage capacity to achieve the target. The bill also prohibits utilities from owning behind-the-meter storage, except for the recent pilot program approved for Liberty Utilities, and directs the Commission to create a statewide "bring your own device" peak reduction program for behind-the-meter storage that also includes special tariffs to compensate projects for peak reduction and avoided transmission and distribution values. The Commission is also authorized to create special tariffs for front-of-the-meter storage projects. The bill also allows utilities to contractually sell the right to bid utility-owned storage projects into wholesale electricity markets. An amended version of the bill passed in March 2019. The amended bill includes a definition for front-of-the-meter storage and removes the provision prohibiting utilities from owning behind-the-meter storage. The amended version instead requires that any utility proposed behind-the-meter storage project or program incorporate a meaningful opportunity for non-utilities to develop and own a significant portion of the storage systems within the program.	H.B. 715 (P1)
	Use of Public Funds	S.B. 205 allows system benefits charge funds to be used for energy storage systems. The bill was amended before it passed the Senate, and this provision was removed.	S.B. 205 (Relevant provisions amended out)
NJ	AMI Rules	A.B. 2994, introduced in February 2018, prohibits utilities from installing smart meters unless the customer has provided written consent and been provided with a disclosure	A.B. 2994 (I)

		detailing the type of data that will be transmitted and how it will or will not be shared.	
	AMI Rules	S.B. 54, introduced in January 2018, requires utilities to install smart meters at the request of the customer. The bill also provides that these costs will be recoverable in a utility's rate base.	S.B. 54 (I)
	AMI Rules	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Cloud Program includes deployment of AMI throughout PSE&G's service territory. PSE&G proposed a $20 monthly fee for residential customers opting out of AMI installation, while commercial and industrial customers will not have the option of opting out. Residential customers requesting the replacement of a smart meter with a traditional meter will be charged a one-time fee of $45.	PSE&G Regulatory Filings (Docket No. EO18101115)
	AMI Rules, Data Access	S.B. 603 and A.B. 3732, introduced in January and March 2018, direct the Board of Public Utilities to open a proceeding to allow the state's utilities to deploy AMI throughout their service territories. Utilities would be required to obtain customer approval before installing each smart meter. The proceeding is also to address data access issues. Upon completion of the Board's proceeding, each utility is to file a proposed smart meter procurement and installation plan. Costs may be recovered in a utility's rate base, although lost or reduced revenue due to reduced electricity consumption will not be considered.	A.B. 3732 (I) S.B. 603 (I)
NM	Energy Storage Cost Recovery, Renewable Portfolio Standard	S.B. 489 establishes criteria for certificates of public convenience and necessity for energy storage systems. The Public Regulation Commission is to approve systems that (1) reduce costs by deferring the need for generation, transmission, or distribution investments; (2) reduce fossil fuel use for meeting peak demand or providing ancillary services; (3) assist with grid reliability and integrating renewable resources; (4) support energy diversification and grid security; (5) reduce greenhouse gas emissions from power generation; (6) provide the utility with discretion to operate, maintain, and control storage systems to ensure reliable and efficient service;	S.B. 489 (E)

		and (7) are the most cost-effective option among alternatives. The bill also allows renewable resources paired with energy storage to be used for renewable portfolio standard compliance. The bill was enacted in March 2019.	
	Renewable Portfolio Standard	H.B. 15 allows renewable energy resources paired with energy storage to be used by public utilities for renewable portfolio standard compliance. The bill did not advance during the 2019 legislative session.	H.B. 15 (D)
NV	Energy Storage Target	S.B. 204, enacted in May 2017, requires the Public Utilities Commission of Nevada (PUCN) to determine whether it is in the public interest to adopt annual requirements for the procurement of energy storage by utilities. In making the determination, the PUCN must study all measurable costs and benefits. In July 2017, the PUCN opened a docket to implement the legislation, and workshops were held in November 2017 and February 2018. The Governor's Office of Energy issued the 2018 Nevada Energy Storage Study RFP in February 2018, and later selected the Brattle Group to conduct the study. The Brattle Group submitted its energy storage study in early October 2018. The study finds that by 2020 up to 175 MW of utility-scale battery storage could be deployed cost-effectively statewide, increasing to 700 MW - 1,000 MW by 2030. Additionally, behind-the-meter storage could add up to 30 MW of storage capacity by 2030. In December 2018, the Commission issued an order accepting the report and its recommendation to proceed to a rulemaking phase to develop a regulation establishing an energy storage target. A workshop is scheduled for May 2019 to discuss a collaborative process for establishing regulations.	S.B. 204 (2017) Docket No. 17-07014 The Economic Potential for Energy Storage in Nevada (The Brattle Group) Order (Dec. 2018)
	Renewable Portfolio Standard	A.B. 206 allows energy storage to count towards the state's renewable portfolio standard. Additionally, one kWh delivered by an energy storage system, which was generated by a renewable resource, will count at two kWh for compliance purposes, subject to some limitations.	A.B. 206 (I)
NY	AMI Rules	A.B. 185 requires AMI opt-out provisions to be included in utility smart grid deployment plans.	A.B. 185 (I)
	AMI Rules	A.B. 3939 and S.B. 1618 prohibit the installation of advanced meters unless they met certain radio frequency and accuracy standards, and	A.B. 3919 (I) S.B. 1618 (I)

	allow customers to opt out of AMI installation with no penalty, fee, or service charge.	
AMI Rules	A.B. 4388 prohibits AMI deployment unless the meters meet certain radio frequency, accuracy, and performance standards; requires 90-day notice of installation of a two-way smart meter; and requires utilities to allow customers to opt out of two-way smart meter installation.	A.B. 4388 (I)
AMI Rules	S.B. 1617 provides that residential customers will have the option to continue with their current electric meter or acquire a real-time smart meter (either by purchasing or renting it from their electric supplier or a third party certified by the Public Service Commission). The bill requires that residential customers opting for a real-time smart meter be on TOU rates. The Commission is also to establish real-time smart metering pilot programs.	S.B. 1617 (I)
Data Access	In April 2018, the New York Public Service Commission issued an order requiring utilities to apply a privacy standard before granting access to aggregated building energy use data to building owners or their authorized agents. In June 2018, the utilities jointly submitted proposed data terms and conditions for access to building data. The PSC issued an order approving the utilities' proposed Whole Building Data Terms and Conditions in early January 2019. In early February, 2019, the City of New York filed a petition for reconsideration of the order approving the data terms and conditions. A working group meeting for the development of Green Button Connect terms and conditions was held in late February 2019.	Docket No. 16-01444 Docket No. 14-M-0101
Data Access	In November 2018, National Grid released a report detailing its proposed deployment of AMI infrastructure. This report also proposes that National Grid will implement the Green Button Connect My Data initiative as part of its AMI deployment.	Case No. 17-E-0238
Data Access, Energy Storage Target	In June 2018, the New York State Department of Public Service and the New York State Energy Research and Development Authority (NYSERDA) released an Energy Storage Roadmap. This document is a plan to achieve the Governor's announced goal of deploying 1,500 MW of energy storage in New York by 2025. In December 2018, the Public Service Commission adopted an energy storage target and roadmap for deploying 1,500 MW of storage	Docket No. 18-00516/18-E-0130 NYSERDA Website

	by 2025 and 2,000 MW by 2030. The Commission also directed the utilities to work with NYSERDA to develop a pilot DER data platform including customer and system data to aid DER developers. In February 2019, the PSC announced the formation of a working group on market design and integration, with a meeting held on March 5, 2019. A conference of the working group was held later in March 2019.	
Energy Storage Compensation	In April 2018 the New York Public Service Commission (PSC) issued an order directing the utilities to submit a draft tariff for a combined solar and storage system. In June 2018 the utilities submitted a draft tariff for combined solar and storage systems. In early October 2018, several parties filed comments expressing concern with the draft tariff's compensation system for energy sent to the grid by the energy storage system. Under the draft tariff, energy from the energy storage system would be compensated through a separate value stack than energy produced directly by the solar system. Commenters expressed concern that this could result in the emission reduction value of energy produced by the solar system and stored in the battery being neglected. Commenters suggested alternative ways of dealing with this issue; two commenters suggested using an "electron tagging" system to assign emission reduction value to a certain proportion of energy from storage systems, while another commenter suggested making solar + storage systems that charge the storage exclusively with electricity from the solar system be allowed full value stack participation. In December 2018, the PSC issued an order accepting the Hybrid Tariff for compensation of distributed energy systems that include battery storage (hybrid facilities). The interconnection of hybrid facilities was approved by a PSC order in April 2018. The Hybrid Tariff provides that the energy injected through a storage medium does not receive the Environmental Value (E), and the MTC credit under the value stack. The tariff includes four options: Option A and Option B offer E, MTC and Capacity Value for all injections by ensuring that only renewable energy injected, Option C uses multiple meters to determine whether injections are from renewable energy or not, and Option D uses monthly netting. On March 29, 2019 and April 1, 2019, the utilities filed updated tariffs for Remote Net Metering and Community Distributed	Docket No. 18-00099/18-E-0018 Docket No. 17-01276 Docket No. 15-02703/15-E-0751 NYSERDA VDER Website

		Generation, which make standalone energy storage systems eligible for these programs, in accordance with notification from PSC Staff received on February 22, 2019 that these technologies were intended to be eligible for these programs in the September 12, 2018 order on value stack eligibility expansion.	
	Energy Storage Compensation	In September 2018, the New York Public Service Commission issued an order extending eligibility for value stack compensation to additional technologies, including standalone energy storage systems. In December 2018, the PSC Staff published a white paper on future value stack compensation and for avoided distribution costs. In mid-April 2019, the PSC issued an order making several significant changes to value stack compensation, following from the recommendations made in the compensation and capacity value white papers written by PSC Staff last year. The rules adopted by the order are not identical to the recommendations from the white papers. While Staff had recommended eliminating Locational System Relief Value (LSRV) due to administrative complexity, the April 18 order instead creates a new method for calculating LSRV based on a call system. The order also makes DG projects with 750 kW or less in capacity eligible for Phase One net metering, where they were previously required to use the value stack, and adopts a new Community Credit for community distributed generation projects to replace the Marginal Transition Credit. The April 18 order also calls for a docket to be opened to examine the utilities' marginal cost of service studies.	Matter No. 15-E-0751/15-02703 Docket No. 17-01276 NYSERDA VDER Website
	Self-Directed Program	A.B. 2282 and S.B. 3410 create a self-directed program for industrial, commercial, and large energy users to encourage greater adoption of advanced energy management projects and DERs, among other goals. This program would allow these entities to use funds collected under various surcharges to be used directly for advanced energy management projects and DERs, including storage. The program is available to customers with a 36-month average demand of 2 MW or more and customers with an aggregated 36-month average demand of 4 MW or more (as long as one of the aggregated accounts has a 36-month average demand of at least 1 MW).	A.B. 2282 (I) S.B. 3410 (I)
OH	Data Access	In December 2017, First Energy filed a plan outlining a three-year $450 million investment in	Docket No. 17-2436-EL-UNC

		the modernization of its distribution network. The utilities, Commission Staff, and other parties filed a stipulation in November 2018, which includes data access enhancements for customers and competitive suppliers. The enhancements include a customer portal, with data downloadable in Green Button format. The Attorney Examiner established a procedural schedule in November 2018 to consider the stipulation. An evidentiary hearing took place in February 2019.	Stipulation
	Data Access	The Public Utilities Commission of Ohio (PUCO) opened three new dockets in October 2018 to build upon the PowerForward investigation. The Data and Modern Grid Workgroup docket will address the following tasks: creating protocols for data privacy protections; driving toward real-time or near real-time data becoming available; and prescribing methodology for competitive retail electric service (CRES) providers and other third parties to obtain customer energy usage data, including a method for CRES providers to obtain the total hourly energy obligation, peak load contribution, and network service peak load. The Commission directed staff in late November 2018 to issue a request for proposal for consulting services to assist with the facilitation of the Data and Modern Grid Workgroup. In January 2019, PUCO selected EnerNex to assist with facilitation of the working group, and the group held its first meeting in March 2019.	Docket No. 18-1597-EL-GRD
OR	AMI Rules	H.B. 3174 requires utilities to provide an analog meter option for a residential customer that does not wish to have a smart meter installed at the residential customer's location. The Public Utility Commission will require a utility to provide an analog meter to a customer that exercises the analog meter option at no cost.	H.B. 3174 (I)
	Building Requirements	H.B. 2496 adds battery storage to the definition of "green energy technology." Public buildings contracting for major renovations (over 50% of the value of the building) are currently required to determine whether green energy technology is appropriate for the building and ensure the public improvement contract includes at least 1.5% of the contract price for green energy technology, if determined to be appropriate	H.B. 2496 (I)
	Building Requirements	H.B. 2497 adds battery storage to the definition of "green energy technology" for emergency shelters and facilities for public safety as long as the battery storage is part of a system generating	H.B. 2497 (I)

		electricity from solar or geothermal energy. Public buildings contracting for major renovations (over 50% of the value of the building) are currently required to determine whether green energy technology is appropriate for the building and ensure the public improvement contract includes at least 1.5% of the contract price for green energy technology, if determined to be appropriate	
	PURPA Rules	The Oregon Public Utility Commission opened two proceedings in February 2019 to investigate the state's implementation of the federal Public Utility Regulatory Policies Act (PURPA), based on the recommendation of the Commission Staff. Docket No. UM 2000 is a broad investigation of PURPA, and Docket No. UM 2001 will consider interim action while the broad investigation continues. The Staff's report that led to the opening of the dockets outlines several issues to be considered in the proceedings. Among those issues are questions related to the treatment of energy storage under PURPA. Specifically, the Staff questions the availability of pricing for renewable resources paired with storage. Staff would also like to explore the value of storage and rates paid to such QFs. As required by a March 2019 order, the utilities filed their avoided cost rates, and the Staff filed a series of questions for participants to respond to in advance of a public workshop in early April 2019. The Staff must also present a final recommendation for enhanced public information about interconnection for consideration at a June 2019 Public Meeting.	Docket No. UM 2000 Docket No. UM 2001
PA	AMI Rules	H.B. 311 allows customers to opt out of AMI installation. The Commission is to establish a surcharge for customers opting out of AMI. The surcharge must reflect actual costs and may include an upfront fee and monthly fee.	H.B. 311 (I)
	AMI Rules, Data Access	H.B. 313 allows customers to opt out of AMI installation. The Commission is to establish a surcharge for customers opting out of AMI. The surcharge must reflect actual costs and may include an upfront fee and monthly fee. The bill also requires utilities to provide, with customer consent, customer meter data to government agencies. Currently, meter data is required to be provided, with customer consent to third parties, but does not specify government agencies as a part of this group. The bill also adds a provision that customer consent is not required if the information is released in aggregate form.	H.B. 313 (I)

	Data Access	H.B. 310 requires utilities to provide, with customer consent, customer meter data to government agencies. Currently, meter data is required to be provided, with customer consent to third parties, but does not specify government agencies as a part of this group. The bill also adds a provision that customer consent is not required if the information is released in aggregate form.	H.B. 310 (I)
SC	Energy Storage Compensation, Interconnection, PURPA Rules	Among other changes, H.B. 3659 and S.B. 332 require the Public Service Commission to address the addition of energy storage to PURPA projects and the interconnection process for energy storage. Additionally, the bills require planned generation facilities to be compared to other generation options before construction may begin. The bills also add energy storage to the definition of customer-generator (and therefore eligible for net metering), as long as the system is configured to charge only from an on-site renewable energy source. H.B. 3659 passed the House in February 2019.	H.B. 3659 (P1) S.B. 332 (I)
TN	Data Access	H.B. 1149 and S.B. 526 prohibit utilities from selling, sharing, or disclosing data collected from AMI to third parties unless the information is aggregated.	H.B. 1149 (I) S.B. 526 (I)
TX	AMI Rules	In July 2018, the Texas Public Utilities Commission opened a proceeding to review Section 25.130 of the Texas Administrative Code, which contains rules on advanced metering. Later in July 2018, AEP Texas, CenterPoint Energy Houston, Oncor, and Texas New Mexico Power submitted a joint proposal of suggested revisions to the rules. The utilities' suggested changes include removing the requirement that advanced meters provide a means for retail electric providers (REP) to provide price signals to customers, removing the requirement that advanced meters provide home area network (HAN) functionality, and removing the provision allowing REPs to require transmission and distribution utilities to provide non-standard meters or meter features. The utilities also proposed that a process be created through which the minimum service features for advanced meters could be amended by the Commission. No action occurred during Q4 2018 or Q1 2019.	Docket No. 48525 16 TAC Section 25.130
	AMI Cost Recovery	H.B. 853 and S.B. 512 make certain utilities (including El Paso Electric) that are subject to cost-of-service regulation and formerly part of	H.B. 853 (I) S.B. 512 (I)

	the Southwest Power Pool able to recover costs for deployment of advanced metering and meter information networks, subject to Public Utility Commission approval that the costs are reasonable and necessary. The bill also requires that utilities deploying an advanced metering information network do so as rapidly as practicable.	
AMI Cost Recovery	H.B. 986 and S.B. 566 make certain utilities (including Xcel-SPS) that are not part of ERCOT able to recover costs for deployment of advanced metering and meter information networks, subject to Public Utility Commission approval that the costs are reasonable and necessary. The bill also requires that utilities deploying an advanced metering information network do so as rapidly as practicable.	H.B. 986 (I) S.B. 566 (I)
AMI Cost Recovery	H.B. 1595 and S.B. 454 make utilities (including SWEPCO) that are subject to cost-of-service regulation and formerly part of the Southwest Power Pool but not affiliated with the Southeastern Electric Reliability Council able to recover costs for deployment of AMI and meter information networks, subject to Public Utility Commission approval that the costs are reasonable and necessary. The bill also requires that utilities deploying an advanced metering information network do so as rapidly as practicable.	H.B. 1595 (I) S.B. 454 (I)
Cybersecurity	S.B. 64 directs the Public Utilities Commission to establish a program to coordinate cybersecurity efforts among electric utilities in the state. The program is to provide guidance on cybersecurity best practices and facilitate the sharing of cybersecurity information between utilities.	S.B. 64 (I)
Energy Storage	H.B. 4449 and S.B. 1012 exempt municipal and cooperative utilities that own or operate energy storage equipment from having to register as a power generation company.	H.B. 4449 (I) S.B. 1012 (I)
Energy Storage Cost Recovery	S.B. 1941 allows transmission and distribution companies to enter into agreements with power generation companies to obtain electricity from energy storage facilities within the ERCOT region. The initial version of the bill would have allowed transmission and distribution utilities to own and operate energy storage facilities (up to 10 MW per utility) only when they were unable to obtain the needed storage from power generation companies through a request for proposals. A substituted version of the bill does	S.B. 1941 (I)

		not include the language allowing ownership of storage facilities. The substituted version of the bill passed the Senate on April 17, 2019.	
	Interconnection	H.B. 2860 and S.B. 2066 entitle DG and energy storage customers to timely interconnection, prohibit utilities from charging additional fees to DG and energy storage customers beyond the additional cost necessary to interconnect their system, and establish consumer protections for third-party leases and power purchase agreements.	H.B. 2860 (I) S.B. 2066 (I)
UT	Data Access	H.B. 307 requires electrical corporations to provide non-residential customers with access to their energy usage data, to the extent available with existing meters. The data is to be in 15-minute intervals or the shortest requested interval available. If there are incremental costs associated with providing this access, the electrical corporation is allowed to charge the customer. The Governor signed the bill into law in March 2019.	H.B. 307 (E)
	Energy Storage	S.B. 24, introduced in December 2018, amends the state energy policy by including energy storage and other advanced energy systems in the list of resources that Utah will promote the development of. The Governor signed the bill into law in March 2019.	S.B. 24 (E)
VT	Cybersecurity, Data Access	In February 2017, the Vermont Department of Public Service filed a letter requesting that the Public Service Board hold a status conference on cybersecurity issues related to smart metering. These issues were investigated several years ago and left open. A conference was held in April 2017, and the Department was directed to file proposed cybersecurity principles by April 28, 2017. The Department of Public Service proposed two sets of principles related to privacy and cybersecurity, and workshops were held in November 2017 and February 2018. In February 2019, the Public Utility Commission (formally called the Public Service Board) adopted the data privacy statement.	Docket No. 7307
	Data Access	In January 2019, Green Mountain Power and Efficiency Vermont filed a proposed data access standard. An October 2018 order in Docket No. 8316 (an investigation opened in 2014) directed Efficiency Vermont and the state's distribution utilities to file data access standards. In March 2019, the Commission approved the proposed data access standard.	Docket No. 19-0259-PET

	Energy Storage Compensation, Permitting, Renewable Portfolio Standard	H.B. 133 adds energy storage systems (using mechanical, chemical, or thermal processes to store electricity) to the definition of "plant" in 30 V.S.A. § 8002, which relates to the state's renewable portfolio standard. The bill also requires that energy storage facilities with a capacity of 500 kW or more receive a certificate of public good prior to construction. The bill also directs the Public Utility Commission to update its decommissioning and aesthetic rules to include energy storage facilities and to develop recommendations for incorporating energy storage facilities into the state's net metering rules. The Commission is to provide a report with these recommendations to the General Assembly by December 31, 2019. The House passed an amended version of the bill in March 2019. The amended version no longer includes the provisions related to energy storage.	H.B. 133 (Relevant provisions amended out)
	Self-Directed Program	In February 2019, the Vermont Public Utility Commission opened an investigation to establish an Energy Savings Account (ESA) partnership pilot program, pursuant to Public Act 150 of 2018. The pilot program would allow participants' energy efficiency charges to be used for their own energy efficiency projects, rather than participating in system-wide programs of Efficiency Vermont. Under the pilot program, customers would be able to use energy efficiency charge funds for energy efficiency and demand management investments, as well as energy storage. Efficiency Vermont and the filed recommended ESA participant selection criteria in March 2019, which the Department of Public Service supports. A workshop was held on March 19, 2019, and parties filed comments. The Department of Public Service recommended adding a requirement that a customer must pay an average annual energy efficiency charge of at least $5,000 to participate.	Docket No. 19-0302-INV
WA	AMI Rules	The Utilities and Transportation Commission opened a docket in June 2018 to consider modifying existing consumer protection and rules related to AMI. In its initial filing, the Commission presented a series of questions and requested responses from interested parties by September 2018. In December 2018, the Commission published draft rules and accepted comments through January 31, 2019. A public comment hearing was held in February 2019, and a workshop was held in March 2019. Two questions came up during the workshop, which some participants offered to address. The	Docket No. U-180525

	Commission followed up with a filing formally requesting the information.	
Renewable Portfolio Standard	H.B. 1211 and S.B. 5116 increase the state's renewable portfolio standard to require that all retail sales are greenhouse gas neutral by 2030. A portion of the standard can be met with "energy transformation projects" which include energy storage. After 2044, energy transformation projects would no longer be eligible. The Senate passed S.B. 5116 in March 2019, and the House passed it in April 2019.	H.B. 1211 (I) S.B. 5116 (P2)

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

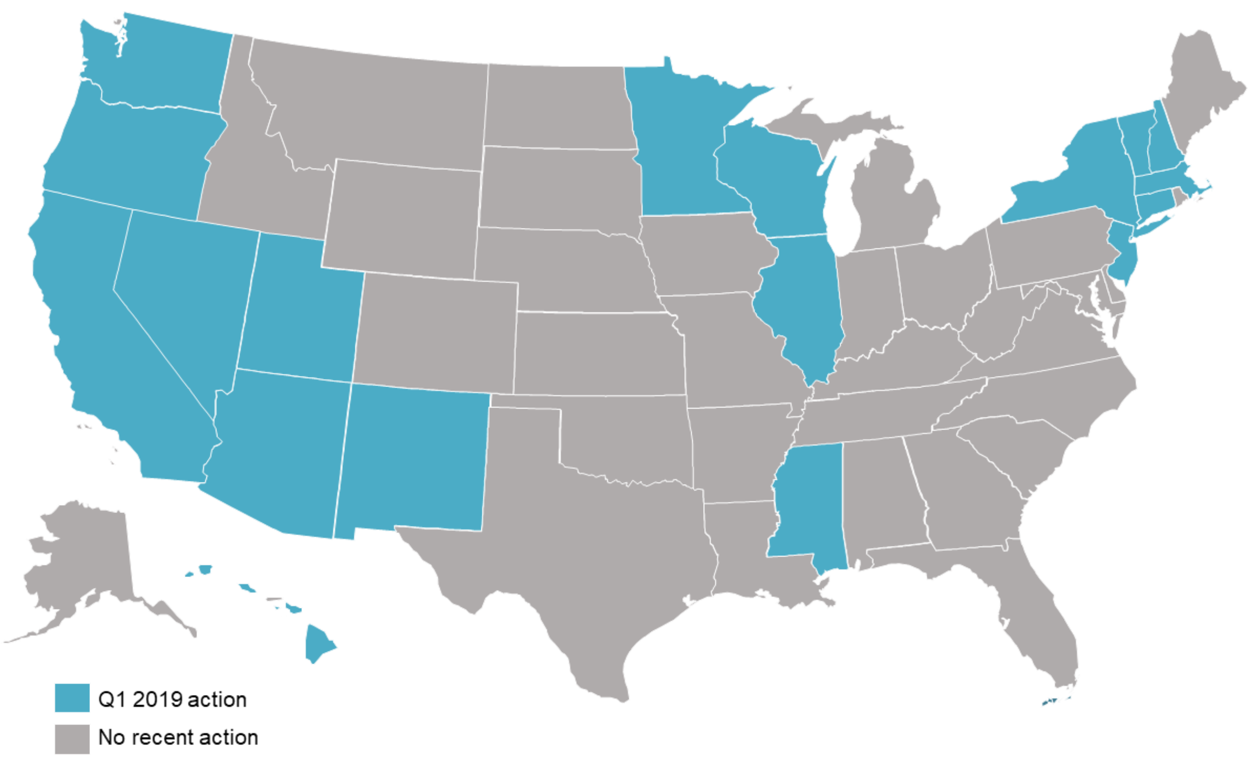
FINANCIAL INCENTIVES

Key Takeaways:

- In Q1 2019, there were 44 actions under consideration in 18 states related to incentives for grid modernization technologies.
- Of these, 36 incentive proposals were for energy storage technologies, while 4 were for demand response, and o was for microgrids. Two proposals would apply to both storage and microgrids, and one would apply to both storage and smart grid technologies.
- Many new actions appeared this quarter as states began their legislative sessions; 27 of the actions considered this quarter were legislative, while 17 were regulatory actions.

In Q1 2019, there were 44 actions under consideration in 18 states related to financial incentives for grid modernizing technologies. These actions include tax credits, property and sales tax exemptions, grant programs, rebate programs, loan programs, and property assessed clean energy (PACE) financing programs.

Figure 16. Action on Financial Incentives (Q1 2019)



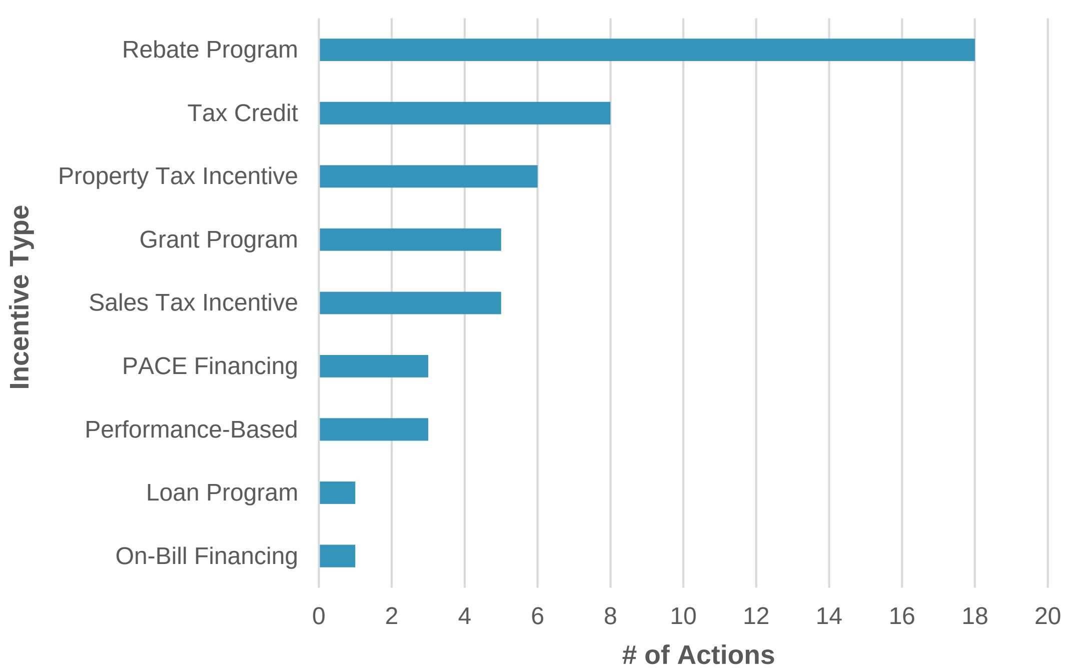
Only one action taken during Q1 2019 approved a new incentive program for grid modernization technology. Massachusetts regulators approved performance-based incentives for customer-owned energy storage, which had been proposed as part of the utilities' joint energy efficiency plans. Customers participating in the program will receive $200 per kWh for dispatching their storage systems during daily peak hours, and $100 per kWh for dispatching during targeted call events. The targeted call incentive was fully approved, and a demonstration version of the daily peak incentive was approved.

Box 5. Tax Incentives, Grants, Rebates, and Financing Programs

The term **tax incentives** covers a broad spectrum of incentives, including income **tax credits** and **deductions**; **property tax exemptions**, exclusions, abatements, and credits; and **sales tax exemptions** and refunds. **Performance-based incentives** are based on the energy production of a system. **Grant programs** are one-time monetary payments, typically awarded through a competitive process, while **rebate programs** provide cash incentives for equipment installations meeting program specifications. Finally, **loan programs** provide financing for the purchase of advanced grid technologies and **Property Assessed Clean Energy (PACE) financing** programs allow property owners to borrow money to pay for certain clean energy improvements and repay the amount via a special assessment on the property. Information about incentives for renewable energy and energy efficiency is included in the Database of State Incentives for Renewables and Efficiency.

Another action of note took place at the federal level. In early April 2019, a member of the U.S. House of Representatives introduced H.R. 2096, which extends federal investment tax credits for renewable energy to energy storage projects. These tax credits are currently scheduled to phase out by 2022 (with a 10% credit remaining indefinitely for commercial and utility-scale projects); this bill does not seek to change the phase-out dates

Figure 17. Q1 2019 Action on Incentives, by Incentive Type



Several bills creating new incentives for grid modernization technologies have advanced in state legislatures this quarter. The Arizona State House passed a bill that would amend the state's existing property and sales tax exemptions for renewable energy systems, expanding them to also include energy storage systems that store renewable electricity. New Hampshire's State Senate advanced a similar bill, which would allow municipalities to exempt energy storage systems from property taxes. The Hawaii State Senate passed an income tax credit bill for energy storage systems paired with renewable generation; the bill originally would have provided this credit to standalone energy storage systems as well, but the amended version that passed the Senate provides the credit only to combined renewable energy and storage systems.

Table 6. Updates on Financial Incentives (Q1 2019)

State	Incentive Type	Description	Source
AZ	Property Tax Incentive, Sales Tax Incentive	H.B. 2617 extends the state's property tax abatement and sales tax exemptions for renewable energy equipment to energy storage projects that store any amount of renewable electricity. The bill also adds energy storage to the types of equipment that local governments may designate renewable energy incentive districts to encourage the development of. Renewable energy incentive districts may include expedited zoning or rezoning procedures, expedited permitting, fee waivers or abatements, and waivers or abatements of development standards.	H.B. 2617 (P1)
	Rebate Program	In early September 2017, Arizona Public Service (APS) filed its application for approval of its 2018 demand-side management plan. As part of its plan, APS proposed a pilot incentive program for grid-connected water heating at residential homes. The incentive would equal about $200. APS has also proposed a pilot measure for free water heater timers to control the timing of electric water heating at residential homes and small businesses. Participants must be on a TOU or demand rate. In early July 2018, Commissioner Olson requested that APS submit the Ratepayer Impact Measure and savings during peak for each program.	Docket No. E-01345A-17-0134
CA	Rebate Program	The Self-Generation Incentive Program (SGIP) provides rebates for energy storage systems. In December 2017, the CPUC issued a ruling establishing a working group to develop changes to the SGIP program to reduce greenhouse gas emissions attributable to energy storage. The working group submitted its final report in June 2018. The report presents the findings of the working group after modeling the greenhouse gas reductions of various energy storage scenarios, including residential and commercial systems with and without solar under old rates and new rates that feature a peak period starting at 3pm or later. The report then provides a list of recommendations. A revised report was released in August 2018, and the CPUC accepted comments in September. In November 2018, the utilities filed a Joint Petition for Modification of a prior decision related to the rules for determining eligibility for incentive adders for equipment manufactured in California. On December 31, 2018, the CPUC released a revised SGIP greenhouse gas proposal for comment. Comments were filed in January 2019.	Docket No. R-12-11-005 Decision No. 17-10-004 Decision No. 17-04-017 Working Group Final Report

Rebate Program	Two separate California bills (A.B. 2514 and A.B. 2868) require the state's IOUs to meet certain procurement targets for energy storage. In February 2018, San Diego Gas & Electric (SDG&E) filed for approval of its 2018 Energy Storage and Procurement Plan, which addresses both the A.B. 2514 and A.B. 2868 targets. Specifically, the plan includes an energy storage incentive program for low-income customers. The proposed program, Energy Storage Incentive for Expanded CARE Pilot Program, would provide an incentive of $1.20 per Watt-hour. A prehearing conference was held on May 1, 2018 to discuss the applications filed by all the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision agrees with SDG&E that it has already satisfied its 2018 A.B. 2514 target and should not hold another solicitation. A proposed decision filed in February 2019 addressed the utilities' A.B. 2868 proposals. The proposed decision approves SDG&E's utility-owned projects provided the utility adheres to guidelines presented in the decision. The proposed decision does not, however, approve the utility's proposed incentive program, arguing that it would overlap with the self-generation incentive program. The proposed decision allows SDG&E to file a new proposal for its incentive program.	Docket No. A18-02-016 October 2018 Decision February 2019 Proposed Decision
Rebate Program	Two separate California bills (A.B. 2514 and A.B. 2868) require the state's IOUs to meet certain procurement targets for energy storage. In March 2018, Southern California Edison filed for approval of its 2018 Energy Storage and Procurement Plan, which includes a $9.8 million incentive program for energy storage installations at low-income multifamily dwellings. The proposed incentive would begin at $0.75 per Watt-hour and step down to $0.60 per Watt-hour. Eligible projects would be sized 100 kWh to 1 MWh. A prehearing conference was held in May 2018 to discuss the applications filed by the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision approved SCE's A.B. 2514 proposal. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision approved PG&E's plan for addressing its residual A.B. 2514 need. A proposed decision filed in February 2019 addresses the utilities' A.B. 2868 proposals. The	Docket No. A18-03-002 October 2018 Decision February 2019 Proposed Decision

		proposed decision denies both of Southern California Edison's proposed projects and provides guidance for the types of program revisions that would be acceptable.	
CT	Grant Program	The Connecticut Green Bank filed a new Technology Eligibility application under the Connecticut Electric Efficiency Partners (EEP) program in December 2018. The EEP program's primary goal is to reduce peak demand through the use of demand-side technology. The EEP program partners can apply for grants to assist with the implementation of projects. The Green Bank application filed for battery energy storage technology systems (EES) paired with solar PV to be eligible as demand-side management technologies under the EEP program. ESS systems would be installed at residential sites to reduce peak demand as needed throughout the year. ESS will be discharged during ISO-New England summer and winter on-peak hours, and during utility TOU peak hours and charged with solar PV during utility off-peak hours. The Green Bank is seeking to market this technology, and will be providing an incentive from $500/kWh to $325/kWh on a decreasing MW block. Battery storage projects for residential customers are not to receive public funding through the Clean Energy Fund. As part of the Green Bank's application, it requested that certain battery information be kept confidential. In January 2019, the PURA rejected the request for confidential treatment, finding the reasoning inadequate. The PURA scheduled a hearing for April 25, 2019. Briefs are due by May 21, 2019.	Docket No. 18-12-35
HI	Tax Credit	H.B. 202 establishes a tax credit for energy storage systems equal to 25% of the basis (costs for the accessories, energy storage, and installation) for the system. The credit will be available for systems placed in service after December 31, 2018 and before January 1, 2026. The legislation calls for caps on the amount of credit that residential and commercial properties can receive, but leaves blanks for the cap amounts. The credit will reduce to 20% for systems placed in service between January 1, 2026 and January 1, 2027 and then to 15% for systems placed in service January 1, 2027 and later. Combined solar plus storage systems are eligible for the energy storage system tax credit plus one-half of the solar system tax credit also created by the bill.	H.B. 202 (I)
	Tax Credit	S.B. 1163, as introduced, establishes a tax credit for energy storage systems equal to 25% of the basis (costs for the accessories, energy storage, and installation) for the system. The credit will be available for systems placed in service after	S.B. 1163 (P1)

		December 31, 2018 and before January 1, 2026. The credit will reduce to 20% for systems placed in service between January 1, 2026 and January 1, 2027 and then to 15% for systems placed in service January 1, 2027 and later. Combined solar plus storage systems are eligible for the energy storage system tax credit plus one-half of the solar system tax credit also created by the bill. However, as amended, the bill no longer provides a tax credit for standalone energy storage systems. Only the costs associated energy storage systems paired with an eligible renewable energy system can be added to the cost basis of the renewable energy system. The bill, as amended, passed the Senate on March 5, 2019.	
IL	Rebate Program	H.B. 2966 adds a credit for energy storage ($350 per kW capacity) to the DG rebate that utilities must offer under the Future Energy Jobs Act of 2017 once their 5% net metering peak demand cap is reached. The bill also requires utilities to offer compensation for additional smart inverter services provided by customers either in monetary form or in the form of reduced required interconnection upgrades, with the customer choosing which form of compensation to take.	H.B. 2966 (I)
MA	PACE Financing	H. 2831 and S. 1941 make certain resilience measures eligible for commercial PACE financing. These measures include energy storage systems and microgrids, provided that the microgrid incorporates clean energy.	H. 2831 (I) S. 1941 (I)
	Loan, Program, Performance-Based Incentive	In late October 2018, Massachusetts' electric utilities filed their joint statewide electric and gas three-year energy efficiency plan, covering 2019-2021. The proposed plan includes performance-based incentives for customer-owned energy storage. Participating customers with storage systems will receive incentives for dispatching the storage during daily peak hours ($200 per kWh), as well as for dispatching during targeted call events ($100 per kWh). The plan also adds storage to the technologies eligible for the state's HEAT loan program, if the customer is participating in the performance-based incentive program. The Department of Public Utilities approved the targeted dispatch incentive and a demonstration offering of the daily dispatch incentive in January 2019.	Docket No. 18-117 Docket No. 18-118 Docket No. 18-119
	Property Tax Incentive, Rebate Program, Sales Tax Incentive	S. 1977 adds a property tax exemption for energy storage systems being used for the energy needs of taxable property. The exemption is for 20 years from the data of installation. The bill also directs the Department of Energy Resources to develop an	S. 1977 (I)

		incentive program for customer-sited energy storage systems by January 1, 2021. The bill also provides a sales tax exemption for energy storage systems until December 31, 2025.	
	Property Tax Incentive, Sales Tax Incentive	H. 3622 authorizes cities and towns to establish a 20-year property tax exemption for energy storage systems. The bill also establishes a sales tax exemption for energy storage systems until December 31, 2027 and a rebate program for Massachusetts-based companies installing and manufacturing storage systems.	H. 3622 (I)
MN	Grant Program	H.B. 1133 and S.B. 1424 create a grant program to enable school districts to finance the installation of solar and solar plus storage systems on school buildings.	H.B. 1133 (I) S.B. 1424 (I)
	Performance-Based Incentive	In December 2018, Minnesota Power filed a petition for approval of several new demand response programs for large industrial customers. The programs include a short-term emergency capacity product offering a $0.60 per kW credit for monthly interruptible billing demand reduction, a long-term emergency capacity product offering a $7 per kW-month credit for up to 150 MW of capacity and a $30 per MWh credit for customers who disrupt operations for economic reasons, and a surplus capacity product for customers with excess capacity that does not fit into other categories.	Docket No. 18-735
	Tax Credit	H.B. 1317 creates a tax credit for customers of a cooperative or municipal utility who purchase solar. The definition of solar includes systems paired with energy storage. The tax credit declines over time from 15% in 2019 to 11% in 2021 and 2022.	H.B. 1317 (I)
MS	Tax Credit	S.B. 2087 establishes a tax credit for solar energy systems of $1.50 per Watt for the first 8 kW. Energy storage systems paired with solar would receive $0.20 per Watt-hour for the first 20 kWh. The bill did not advance during the 2019 legislative session.	S.B. 2087 (D)
NH	Property Tax Incentive	S.B. 204 authorizes cities and towns to exempt electric energy storage systems from property taxes. The Senate passed the bill in March 2019.	S.B. 204 (P1)
NJ	PACE Financing	S.B. 1611 and A.B. 1902 allow energy storage systems and microgrids to be eligible for property assessed clean energy financing.	S.B. 1611 (I) A.B. 1902 (I)
	Rebate Program	S.B. 599 and A.B. 4009 direct the Board of Public Utilities to establish demand response programs. Utilities are to provide participating customers with a monthly rebate equal to 10% of the customer's	S.B. 599 (I) A.B. 4009 (I)

		monthly bill. Customers are responsible for the purchase and cost of installing any devices required for participation.	
	Rebate Program	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Smart Homes Pilot Program focused on providing comprehensive energy solutions to participants. The program covers a wide variety of technologies, including traditional energy efficiency and smart appliances, as well as battery storage, water heaters, connected PV inverters, and electric vehicles. Rebate levels for platforms or individual devices will be set prior to the subprogram launch. The total proposed budget for the Smart Homes Pilot Program is about $26.3 million.	PSE&G Regulatory Filings (Docket No. EO18101113)
	Rebate Program	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Non-Wires Alternatives (NWA) Pilot Program, which will seek to defer or replace the need for investment in new electric infrastructure through targeted deployment of DG, energy storage, energy efficiency, demand response, and grid software and controls. PSE&G will conduct an analysis to determine the NWA target zones, and will offer incentives to residential, commercial, and industrial customers in these zones to deploy various NWA technologies. The total proposed budget for the NWA Pilot Program is about $26.3 million.	PSE&G Regulatory Filings (Docket No. EO18101113)
NM	On-Bill Financing	H.B. 432 authorizes on-bill financing, for which energy storage would be an eligible measure. The bill did not advance during the 2019 legislative session.	H.B. 432 (D)
	Property Tax Incentive	H.B. 520 exempts from property taxes solar energy systems, including those paired with energy storage systems, that are located on residences of up to 3,000 square feet. The bill did not advance during the 2019 legislative session.	H.B. 520 (D)

	Tax Credit	H.B. 593 creates an income tax credit for energy storage systems installed before January 1, 2025. The amount of the credit is the lesser of 30% of the total purchase and installation cost or $5,000 for a system installed on a commercial property or $150,000 for a system installed on a commercial property. The maximum aggregate amount of tax credits that may be provided each year is $2 million. The tax credit would be non-refundable and would not be able to be carried forward. The bill also establishes a corporate income tax credit for energy storage systems installed before January 1, 2025. The credit amount is the lesser of 30% of the total cost of installation or $50,000. The maximum aggregate amount of corporate tax credits that may be provided each year is $2 million. The bill died at the end of the state's legislative session.	H.B. 593 (D)
NV	Rebate Program	In October 2018, the Public Utilities Commission of Nevada opened a proceeding to establish a working group to make recommendations regarding eligibility for NV Energy's large energy storage incentive program, pursuant to the regulations established in Docket No. 17-08021. The working group is to meet at least once per year. Letters of interest for participation in the working group were due by December 28, 2018. The Commission issued a procedural order in February 2019, again directing parties interested in joining the working group to file a letter of interest by February 13, 2019. Several parties filed letters of interest.	Docket No. 18-10022
	Rebate Program	In February 2019, NV Energy filed its annual plan for program year 2019-2020 incentive programs, including its energy storage incentives. If additional funding is authorized for the energy storage incentive program, NV Energy proposes increasing the non-residential small energy storage incentives from $0.15 per watt-hour for customers on TOU plans and from $0.08 per watt-hour for those on non-TOU plans to $0.35 per watt-hour for non-investment tax credit (ITC) eligible projects and $0.25 per watt-hour for ITC eligible projects. NV Energy also proposed changing the non-residential large energy storage incentive structure to differentiate between ITC-eligible and non-ITC eligible projects. For non-critical infrastructure, the incentive would increase from $0.30 per watt-hour to $0.40 per watt-hour for non-ITC eligible projects and remain at $0.30 per watt-hour for ITC-eligible projects. For critical infrastructure, the incentive would increase from $0.40 per watt-hour to $0.50 per watt-hour for non-ITC eligible projects and remain at $0.40 per watt-hour for ITC-eligible projects. A prehearing conference was held on March 20, 2019. A	Docket No. 19-02001

		procedural order filed in late March 2019 established the schedule for the proceeding, with a prehearing conference and prepared testimony slated for April 2019, and rebuttal testimony and a hearing scheduled for May 2019.	
NY	Grant Program	A.B. 2452 and S.B. 1535 create the Takecharge New York Power program to award microgrid allocations to qualified businesses.	A.B. 2452 (I) S.B. 1535 (I)
	Property Tax Incentive	S.B. 2658 exempts homeowners from real property taxation for energy storage systems paired with renewable energy and with a generation capacity not greater than 20 kW and a storage capacity not greater than 30 kWh.	S.B. 2658 (I)
	Rebate Program	On February 22, 2019, the PSC announced the formation of a working group on market design and integration, with a meeting held on March 5, 2019. On March 11, 2019, NYSERDA filed program manuals for its bulk, market acceleration, and retail energy storage incentives programs (together representing the implementation plan and program manual due on March 11th). A conference of the working group was held in late March 2019.	Docket No. 18-E-0130
	Rebate Program	As part of a joint investment proposal filed in May 2018 by New York State Electric and Gas, Rochester Gas and Electric, the Department of Public Service, the Department of State, the Division of Consumer Protection, and others, the utilities would offer a financial assistance program for back-up power assistance for customers with life-sustaining equipment. The program would cover 50% the cost of qualifying equipment, including battery back-up systems, up to $1,000. The estimated cost of the program is $200,000. The investment proposal is designed to improve grid resiliency and emergency response in the areas impacted by a March 2017 windstorm. Several parties filed statements in support of the proposal in July 2018. Extension requests have been continuously filed in this docket since July 2018; the most recent extension request was filed and approved in January 2019; the proceeding has been extended until April 29, 2019.	Docket No. 17-E-0594/17-00540
	Tax Credit	A.B. 532, introduced in January 2019, establishes the "qualified solar and energy storage manufacturer facilities and operations credit," providing tax credits for solar and storage manufacturing and research companies in the state. The credit is equal to 20% of the cost incurred for research and development and manufacturing property. The bill also includes a credit for 10% of qualified research and manufacturing expenses.	A.B. 532 (I)

	Tax Credit	A.B. 5664 establishes an income tax credit for installation of a residential energy storage system. The credit amount is 25% of the cost of the system, up to a maximum of $7,000.	A.B. 5664 (I)
	Tax Credit	S.B. 3587 adds energy storage and smart grid technologies to the definition of "emerging technologies." Business classified as "Qualified Emerging Technology Companies" may claim capital tax credits.	S.B. 3587 (I)
OR	Rebate Program	In August 2018, Portland General Electric filed for approval to extend the deadline for its Residential Demand Response Water Heater Pilot to March 31, 2019. PGE will provide a $50 sign-up incentive to participating customers, plus $100 to customers who participate for a full year. In September 2018, the Commission Staff recommended approval of the pilot extension.	Docket No. ADV 822
	Rebate Program	H.B. 2618 creates a rebate program for residential and commercial solar and solar-plus-storage systems. The maximum rebate for residential solar-plus-storage systems is 40% of the cost of the solar system (up to $6,000 in 2020, $5,500 in 2021, and $5,000 in 2022 and 2023) plus 40% of the cost of the storage system (up to $2,500). The maximum rebate for commercial solar-plus-storage systems is 30% of the cost of the solar system (up to $40,000 in 2020, $35,000 in 2021, and $30,000 in 2022 and 2023) plus 40% of the cost of the storage system (up to $15,000).	H.B. 2618 (I)
UT	Grant Program	S.B. 111 establishes the Energy Storage Innovation, Research, and Grant Program for both non-residential and residential energy storage projects. At least 60% of the appropriations (total appropriations for the program are $5 million) are to be allocated for residential energy storage grants.	S.B. 111 (D)
	Sales Tax Incentive	H.B. 127 and S.B. 146 create a sales and use tax exemption for electric energy storage assets used for residential, commercial, or industrial purposes. The bills did not advance during the 2019 legislative session.	H.B. 127 (D) S.B. 146 (D)
VT	Performance-Based Incentive	In December 2018, Green Mountain Power filed a letter notifying the Commission that it plans to open its Flexible Load Management and Thermal Energy Storage Innovative Pilot on December 23, 2018. The pilot focuses on using ice storage resources at commercial and industrial customer sites with flexible loads. The utility will provide a credit for peak reduction (sharing 70% of the value with the host customers). The Department of Public Service filed	Docket No. 18A-4147

		comments in December, generally supporting implementation of the pilot, but suggesting that additional regulatory scrutiny is needed as the program is implemented.	
	Rebate Program	In February 2019, Green Mountain Power announced, in partnership with Renewable Energy Vermont, a new incentive option as part of its Bring Your Own Device Program. Green Mountain Power is now offering an upfront incentive of $850 per kW for energy storage systems enrolled in the program. The utility is also offering a $150 per kW incentive to solar owners in certain areas of the grid to add energy storage to their systems. Green Mountain Power controls the storage systems during peak usage times in exchange for the incentive.	Press Release Bring Your Own Device Program
WA	Grant or Rebate Program	S.B. 5981 creates a greenhouse gas cap and trade program in the state. Money received by the state from the distribution of emission allowances will be collected in a Carbon Pollution Reduction Account in the state treasury. Forty percent of those funds will be dedicated to the Energy Transformation Account. Funds in the Energy Transformation Account will be used by the Department of Commerce for projects and incentives that yield verifiable reductions in carbon pollution. The bill lists energy storage as one of the possible target technologies.	S.B. 5981 (I)
	PACE Financing	H.B. 1796 and S.B. 5730 authorize commercial PACE financing, and list energy storage as an eligible property improvement.	H.B. 1796 (I) S.B. 5730 (I)
	Sales Tax Incentive	H.B. 1226 exempts carbon reduction investments from the state share of use taxes. The term carbon reduction investment includes energy storage.	H.B. 1226 (I)
WI	Rebate Program	In January 2019, Northern States Power Company (Xcel Energy) filed an application for approval of a new residential load management program, called AC Rewards. In this program, residential customers would be provided with incentives to install Wi-Fi connected thermostats in exchange for participation in load management events.	Docket No. 4220-TE-103

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

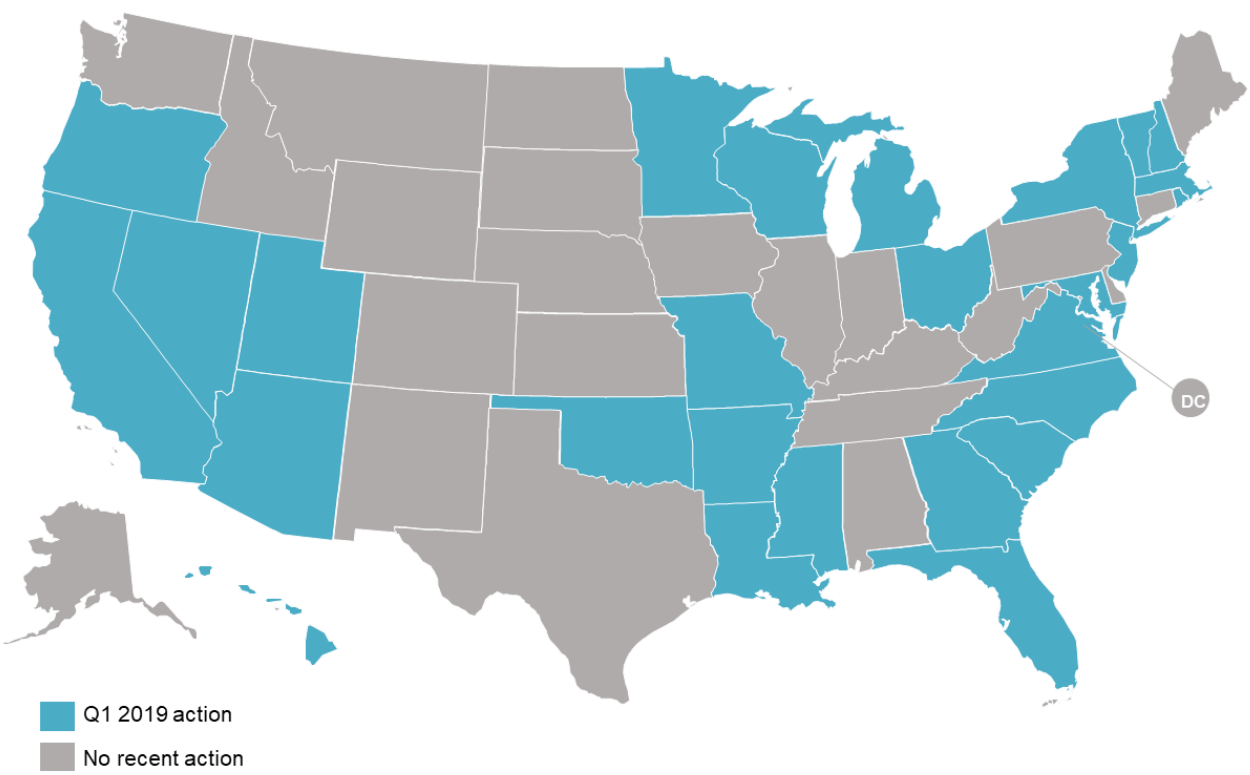
DEPLOYMENT OF GRID MODERNIZING TECHNOLOGIES

Key Takeaways:

- In Q1 2019, there were 62 pending or decided proposals across 27 states to deploy grid modernization technologies, such as advanced metering infrastructure, smart grid technologies, microgrids, energy storage, and demand response.
- The majority of actions related to proposals to deploy energy storage projects, with 38 requests under consideration during the quarter.
- Virginia regulators rejected the majority of Dominion's grid modernization plan, while the Hawaii Public Utilities Commission approved HECO's Phase I grid investments.

Utilities continue to request approval and cost recovery for the deployment of grid modernizing technologies. In Q1 2019, there were 62 legislative or utility deployment proposals under consideration in 27 states. Of these requests, the majority related to energy storage projects, followed by smart grid or distribution system modernization investments.

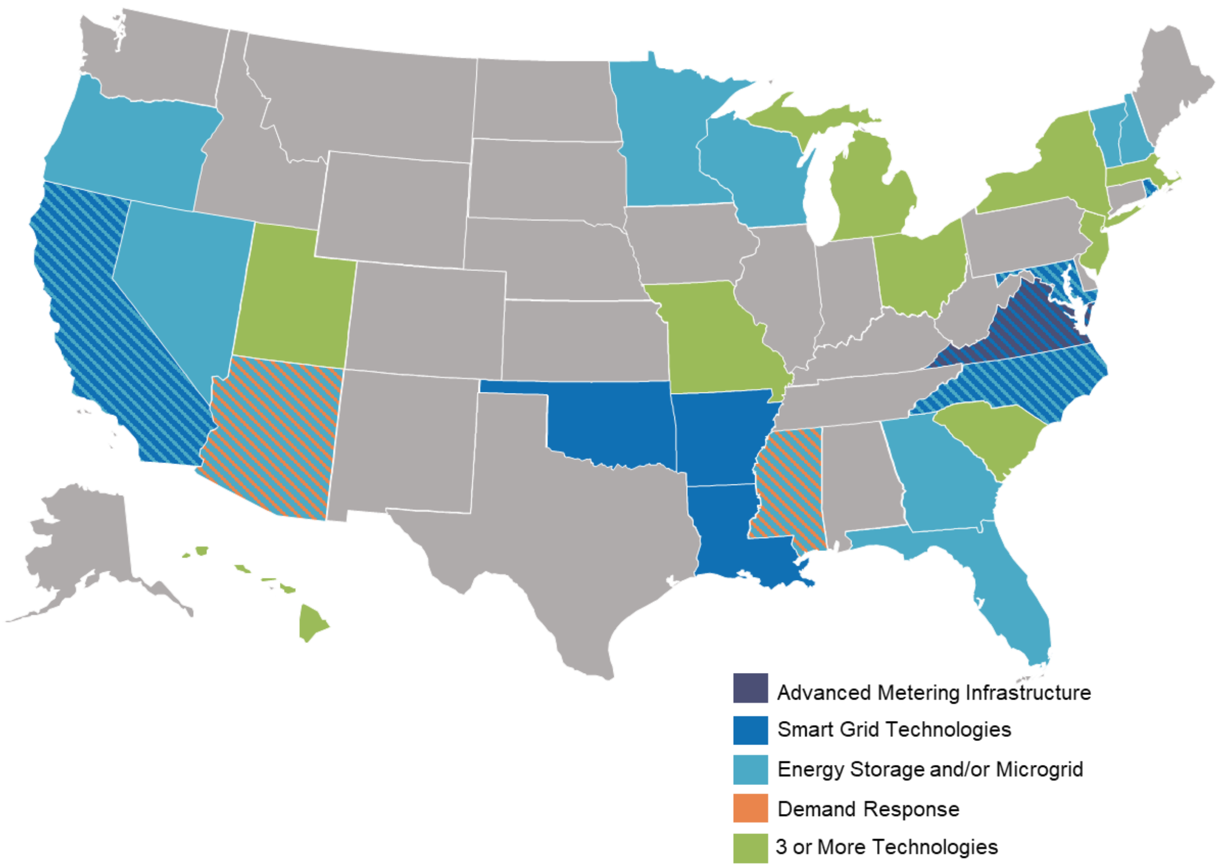
Figure 18. Action on Grid Modernization Technology Deployment (Q1 2019)



Advanced Metering Infrastructure

There were 16 proceedings or bills under consideration in 10 states related to the deployment of advanced metering infrastructure (AMI) during Q1 2019. Hawaii regulators approved an AMI deployment proposal from the HECO Companies, although the deployment is subject to a cost cap. In Missouri, Ameren proposed a capital investment plan including $245 million for AMI deployment. In Virginia, regulators denied Dominion Energy's AMI deployment request, and Appalachian Power withdrew its AMI deployment proposal in order to ensure it aligns with the requirements laid out in the Dominion case. At the end of Q1 2019, dockets considering AMI deployment requests were open in Michigan, Missouri, New Jersey, New York, Ohio, and South Carolina.

Figure 19. Proposed Deployments by Technology Type (Q1 2019)



Smart Grid / Distribution System Modernization

There were 26 open proceedings or bills under consideration in 16 states related to smart grid technology deployment and distribution system modernization. Maryland regulators approved Potomac Edison's distribution automation equipment deployment proposal, and the Arkansas Public Service Commission approved a smart grid deployment request by Oklahoma Gas & Electric. In Oklahoma, Public Service Company of Oklahoma had initially requested cost recovery for several smart grid investments as part of a rate case, but the approved settlement agreement for this case excluded the smart grid investments. Appalachian Power in Virginia withdrew its proposed grid transformation projects after the Commission denied a similar proposal from Dominion.

Table 7. Proposed AMI and Grid Modernization Investment Plans (Q1 2019)

State	Utility	Proposed Budget	Approved Budget
Arkansas	Oklahoma Gas & Electric	$20 Million	$20 Million
California	Southern California Edison	$2.1 Billion	Pending
Hawaii	HECO, HELCO, MECO	$86.3 Million	$86.3 Million
Louisiana	Entergy New Orleans	$59.3 Million	Pending
Maryland	Potomac Edison	$10.7 Million	$10.7 Million
Michigan	Upper Peninsula Power Co.	$15.6 Million	Pending
Missouri	Ameren Missouri	$5.3 Billion	Pending
New Jersey	Atlantic City Electric	$338.2 Million	Pending
New Jersey	Jersey Central Power & Light	$386.8 Million	Pending
New Jersey	PSE&G New Jersey	$810.3 Million	Pending
New York	National Grid	$446.35 Million	Pending
New York	PSEG Long Island	$204 Million	Pending
Ohio	Dayton Power & Light	$866.9 Million	Pending
Ohio	First Energy	$450 Million	Pending
Ohio	First Energy	$600 Million	Pending
Oklahoma	Public Service Co. of Oklahoma	$175 Million	$0
South Carolina	Duke Energy Carolinas, Duke Energy Progress	$455 Million	Pending
Virginia	Appalachian Power	$587.4 Million	$0 (Withdrawn)
Virginia	Dominion Energy	$1.49 Billion	$154.5 million
TOTAL		$14.4 Billion	$271.5 Million

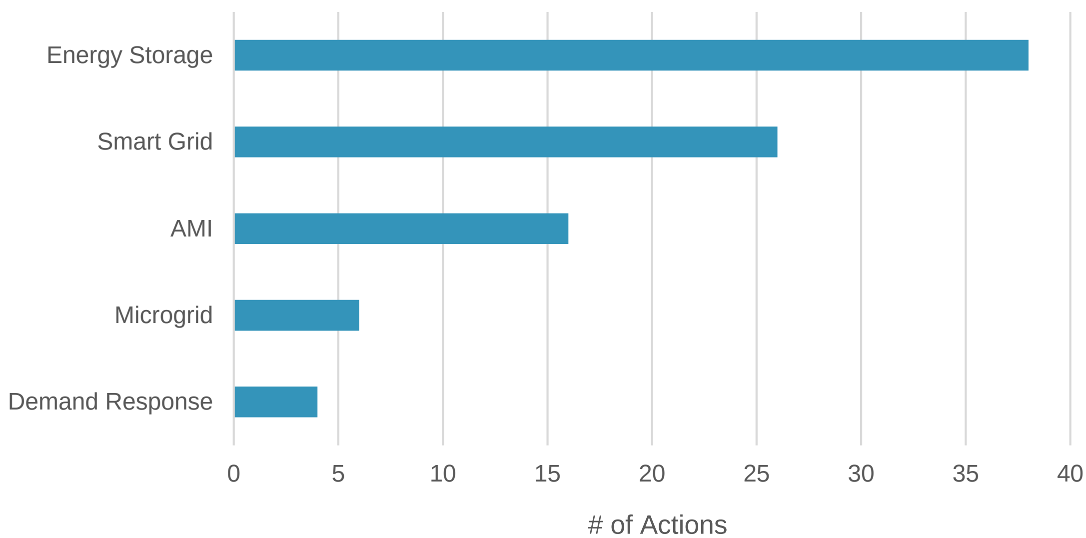
Energy Storage

There were 38 open proceedings or bills under consideration in 24 states related to energy storage deployment. New Hampshire regulators approved a residential battery storage pilot program from Liberty Utilities. Nevada Energy took bids for long-term firm capacity and energy resources, with the RFP including standalone energy storage systems. New York's investor-owned utilities filed implementation plans for the procurement of energy storage resources under the Energy Storage Roadmap, with tariffs for these procurement programs planned to be released next quarter. Both chambers of the Maryland General Assembly passed a bill creating an energy storage pilot program testing several different regulatory models, although the bills have not yet been signed.

Microgrids

There were six open proceedings or bills under consideration in five states related to the deployment of microgrids, including pilot projects aimed at learning more about microgrid capabilities and benefits. As part of Liberty Utilities' general rate case filed in California in January 2019, the utility requested approval for a new microgrid, and two microgrid projects proposed by Green Mountain Power were approved in Vermont during Q1 2019. The North Carolina Public Staff recommended approval of a microgrid proposed by Duke Energy Progress.

Figure 20. Proposed Deployments by Technology Type (Q1 2019)



Demand Response

There were four open proceedings related to demand response deployment in four states during Q1 2019. DTE Electric in Michigan included an increase in demand response programs to 859 MW by 2024 in its latest integrated resource plan, and Dayton Power & Light in Ohio requested approval for a new residential demand response pilot program. No demand response deployment requests were approved or denied during the quarter, but proposals remained under consideration in Arizona and Mississippi.

Table 8. Updates on Advanced Grid Technology Deployment (Q1 2019)

State	Utility	Technology	Description	Source
AR	Oklahoma Gas & Electric	Smart Grid	In October 2018, Oklahoma Gas & Electric filed its formula rate plan application, including a request for approval of certain grid modernization investments totaling $20 million. The proposed investment breaks down to 46% structural integrity, 16% functional integrity, and 38% grid technology enhancements and will focus on 14 circuits. New technology being deployed includes automated reclosers and switches. In late January 2019, a non-unanimous settlement agreement was filed by Oklahoma Gas & Electric, the Commission Staff, the Attorney General, and the Arkansas River Valley Energy Consumers. The settlement agreement approved the proposed grid modernization investments, but only for the current projected year. Approval for any future grid modernization investments would need to be requested in future evaluation reports. The settling parties proposed that the evidentiary hearing scheduled for February 2019 be canceled. The Commission issued an order canceling the hearing in early February. The Commission approved the settlement agreement in March 2019.	Docket No. 18-046-FR
AZ	Arizona Public Service	Energy Storage	In early March 2019, Arizona Public Service requested approval to recover the costs associated with two energy storage agreements through its Power Supply Adjustor. The two agreements are for energy storage procured through its 2018 Peaking Capacity RFP. One agreement is for a 100 MW / 400 MWh storage project and the other is for a 50 MW / 200 MWh storage project.	Docket No. E-01345A-19-0049
	Arizona Public Service	Reverse Demand Response	In early September 2017, Arizona Public Service (APS) filed its application for approval of its 2018 demand-side management plan. As part of its plan, APS proposed a new "reverse demand response" pilot program for non-residential customers with demand of at least 30 kW. This program would identify opportunities to dispatch loads in response to negative pricing events. Participation is limited to non-essential loads, which would receive	Docket No. E-01345A-17-0134

			no-cost energy during specified time periods. The proposed program would be limited to $200,000, and APS would deploy necessary sub-metering and communications infrastructure.	
CA	IOUs	Energy Storage	S.B. 774 states the intent of the Legislature to enact later legislation to require the Commission to develop and implement a program to deploy local clean energy generation and storage systems throughout California.	S.B. 774 (I)
	Liberty Utilities	Energy Storage	Liberty Utilities filed an application in November 2017 for approval of a 2.6 MW / 15 MWh battery storage system. The main goals of the project are to improve the quality of electricity to its customers, improve system reliability, and improve safety. The total cost is estimated to be $8.4 million. Liberty Utilities filed a brief in support of its proposal during Q3 2018. An ALJ filed a ruling in November 2018, directing Liberty Utilities to file supplemental testimony by December 10, 2018. The ruling includes 12 specific questions related to the proposed project, the reliability issues the utility is seeking to address with the project, and the bidding process the utility went through to select a vendor. In February 2019, Liberty Utilities requested an evidentiary hearing. The Commission responded with a ruling directing Liberty Utilities to file a formal motion requesting the evidentiary hearing.	Docket No. A-17-11-014
	Liberty Utilities	Energy Storage, Microgrid	As part of Liberty Utilities' general rate case filed in December 2018, the utility proposed deploying AMI in its service territory for $9 million. The utility also proposed $4.3 million in investment in Supervisory Control and Data Acquisition (SCADA) and Transfer of Authority (TOA) systems. The case also includes a planned microgrid project for $16.4 million, including $14.4 for battery storage related costs. The battery storage within the microgrid would be 8 MW / 32 MWh in size and duration. The plan also includes a 2.6 MW / 15 MWh battery storage system to install in Alpine County for $8.4 million, due to the high level of outages on this circuit. A scoping ruling filed in March 2019 established the schedule for the proceeding through October 2019.	Docket No. A-18-12-001

Pacific Gas & Electric	Energy Storage	Two separate California bills (A.B. 2514 and A.B. 2868) require the state's IOUs to meet certain procurement targets for energy storage. In March 2018, Pacific Gas & Electric (PG&E) filed for approval of its 2018 Energy Storage and Procurement Plan, which includes the deployment of 166 MW of energy storage. Like its previous Energy Storage Procurement Plans, PG&E plans to reach its deployment target primarily though requests for offers. The proposal for its requirements under A.B. 2868 also includes one behind-the-meter storage program, for up to five MW of behind-the-meter thermal storage. A prehearing conference was held in May 2018 to discuss the applications filed by all of the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision approved PG&E's plan for addressing its residual A.B. 2514 need. A proposed decision filed in February 2019 addresses the utilities' A.B. 2868 proposals. The proposed decision denies PG&E's proposed utility-owned program, but approves its behind-the-meter proposal. The proposed decision allows PG&E to file a new proposal for its utility-owned program.	Docket No. A-18-03-001 October 2018 Decision February 2019 Proposed Decision
Pacific Gas & Electric, Southern California Edison	Energy Storage	In December 2017, Pacific Gas & Electric (PG&E) filed for approval of six energy storage agreements resulting from its 2016-2017 Request for Offers. The projects total 165 MW of energy storage capacity. Southern California Edison also filed an application for 10 MW of battery storage. Both utilities proposed to recover costs through their respective Energy Resource Recovery Accounts. A decision issued in October 2018 approves the energy storage agreements and cost recovery mechanisms. The Public Advocates Office filed an application for rehearing of the decision in November 2018, citing issues with one of the projects proposed by PG&E. In December 2018, PG&E and the California Energy Storage Alliance filed responses citing their opposition to the Public Advocates Office's	Docket No. A-17-12-003

		Application for Rehearing. No significant action took place in Q1 2019.	
San Diego Gas & Electric	Energy Storage	Two separate California bills (A.B. 2514 and A.B. 2868) require the state's IOUs to meet certain procurement targets for energy storage. In February 2018, San Diego Gas & Electric (SDG&E) filed for approval of its 2018 Energy Storage and Procurement Plan, which addresses both the A.B. 2514 and A.B. 2868 targets, which includes the deployment of 166 MW of energy storage. A prehearing conference was held in May 2018 to discuss the applications filed by the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision agrees with SDG&E that it has already satisfied its 2018 A.B. 2514 target and should not hold another solicitation. A proposed decision filed in February 2019 addressed the utilities' A.B. 2868 proposals. The proposed decision approves SDG&E's utility-owned projects provided the utility adheres to guidelines presented in the decision.	Docket No. A18-02-016 October 2018 Decision February 2019 Proposed Decision
Southern California Edison	Energy Storage	Two separate California bills (A.B. 2514 and A.B. 2868) require the state's IOUs to meet certain procurement targets for energy storage. In March 2018, Southern California Edison (SCE) filed for approval of its 2018 Energy Storage and Procurement Plan, which includes the procurement of a minimum of 20 MW of energy storage. Specifically, the proposal includes a solicitation for approximately 40 MW of utility-owned energy storage and a $9.8 million incentive program for energy storage installations at low-income multifamily dwellings. A prehearing conference was held in May 2018 to discuss the applications filed by the utilities. A scoping memo and ruling consolidated the three IOUs' energy storage procurement plan proceedings. The Commission filed a decision in October 2018 addressing the utilities' 2018 procurement plans for the A.B. 2514 requirements. The decision approved	Docket No. A18-03-002 October 2018 Decision February 2019 Proposed Decision

			PG&E's plan for addressing its residual A.B. 2514 need. A proposed decision filed in February 2019 addresses the utilities' A.B. 2868 proposals. The proposed decision denies both of SCE's proposed projects and provides guidance for the types of program revisions that would be acceptable.	
	Southern California Edison	Smart Grid	In its latest rate case, Southern California Edison (SCE) proposed an investment of $2.1 billion in capital expenditures from 2016 - 2020 for its Grid Modernization plan, which includes structural upgrades, automation for real-time monitoring and control, new telecommunications capabilities, and new software for system management. An evidentiary hearing was held in March 2018, and a May 2018 decision extended the statutory deadline for the proceeding to December 3, 2018. A decision issued on December 6, 2018 again extended the statutory deadline, now set at June 3, 2019. A proposed decision filed in April 2019 approves most elements of the Grid Modernization plan, but at lower budget levels than those requested by SCE. The proposed decision reduces the 2017-2018 distribution automation funding from SCE's proposed $286.7 million to $141.2 million. It also reduces the 2017-2018 communications funding from SCE's proposed $246 million to $95.7 million. It also approves the full $45.6 requested by SCE for tools for data analysis and decision-making.	Docket No. A-16-09-001 Southern California Edison Proposal
FL	Florida Power & Light	Energy Storage	In March 2019, Florida Power & Light announced its plans to build a 409 MW battery storage system that is to be paired with an existing solar facility.	Press Release
GA	Georgia Power	Energy Storage	In January 2019, Georgia Power filed its 2019 integrated resource plan, which includes a planned procurement of 50 MW of battery storage. The costs for the procurement were redacted from the application. The Commission filed a procedural and scheduling order in February 2019, with a final decision expected by July 16, 2019.	Docket No. 42310
HI	Hawaiian Electric Companies	AMI, Smart Grid	In June 2018, the HECO Companies filed an application for Phase 1 of its grid modernization project, spanning 2019 -	Docket No. 2018-0141

		2023 at a total estimated cost of approximately $86.3 million. Phase 1 includes the deployment of advanced meters, a meter data management system, and a telecommunications network. The forecasted AMI deployment during Phase 1 is over 175,000 meters, and will be deployed during the routine replacement of meters, the installation of new meters, and for customers participating in one of the utilities' DG tariffs. The Division of Consumer Advocacy filed a Statement of Position in November 2018 citing concerns with the application but ultimately recommending it subject to multiple conditions based on the urgent need to begin smart meter deployment. In December 2018, the HECO companies submitted a reply statement in response to the Division's Statement of Position, defending the companies' proposal. A March 2019 order approved HECO's application, subject to certain cost recovery caps detailed in the order. There is a fixed cost recovery cap for the data management system, and a variable cap for the AMI deployment assessed on a dollar-per meter basis. This decision allows the overall approved costs of Phase 1 to be higher than the $86.3 million proposed if the companies exceed their proposed advanced meter deployment in Phase 1. The order also requires HECO to file semi-annual progress reports on Phase 1 starting on June 20, 2019.	Phase I Grid Modernization Strategy Order
Hawaiian Electric Companies	Energy Storage	In May 2018, the HECO Companies filed an application for a 20 MW battery capable of storing 80 MWh of energy at the West Loch Naval Annex, the site of a planned grid-scale PV project. Construction on the project is scheduled to start in October 2019 with the unit placed in service in February 2020. The total estimated cost is $43.5 million. The Companies proposed recovering the project's costs through the Major Project Interim Recovery Mechanism. An ultimate decision is expected in April 2019. HECO filed an information request response in January 2019, and the Division of Consumer Advocacy requested an extension for the filing of Statement of	Docket No. 2018-0102

			Position (SOP) and reply SOP, which the Commission granted.	
	Hawaiian Electric Companies	Energy Storage	In May 2018, the HECO Companies filed an application for a 100 MW battery energy storage system capable of storing 100 MWh of energy at Hawaiian Electric's Campbell Industrial Park Generating Station. Construction on the project is scheduled to start in October 2019 with an in-service date of October 2020, at a total estimated cost of $104 million. The Companies proposed recovering the project's costs through the Major Project Interim Recovery Mechanism. An ultimate decision is expected in April 2019. HECO filed an information request response in January 2019, and the Division of Consumer Advocacy requested an extension for the filing of Statement of Position (SOP) and reply SOP, which the Commission granted.	Docket No. 2018-0103
LA	Entergy New Orleans	Smart Grid	In Entergy New Orleans' general rate case filed in September 2018, the utility requested cost recovery for five grid modernization projects. The five projects include installation of 40 self-healing network areas, 545 smart devices, and 109.8 line miles of new conductor. The total estimated cost of the projects is $59.3 million. Entergy proposed recovering portions of the projects closing before December 31, 2019 through base rates and the remainder through a new Distribution Grid Modernization Rider (Rider DGM). Future grid modernization projects would also be recovered through Rider DGM. Entergy also proposed a process for the review of new grid modernization projects, including a six-month timeframe. The utility also requested approval for a new cost recovery mechanism for its demand-side management (including demand response) initiatives. Entergy proposed a new rider, Rider DSMCR, to fund its Energy Smart programs for program year 10 and beyond. The proposed rider would include direct and indirect costs of the demand-side management offerings, lost contributions to fixed costs, and some type of an incentive. Entergy would earn a return on its demand-side management	City Council Docket No. 18-07

			offerings, in order to put demand and supply resources on a more equal footing.	
MA	Eversource	AMI, Energy Storage, Smart Grid	In accordance with the Department of Public Utilities' (DPU) June 2014 order on grid modernization plans, Eversource filed its grid modernization plan in August 2015. Eversource has proposed investments in advanced sensing technology, next generation remote faulted circuit indication, a distribution management system, network load flow, predictive outage detection, automated feeder reconfiguration, voltage optimization, integrated planning tracking for DERs, energy storage, adaptive protection/two-way power flow, resiliency improvements, opt-in time-varying rates and related infrastructure, cybersecurity, communications, and a customer education and outreach plan. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment proposals, finding that statewide deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $133 million for Eversource, which includes investments in distribution management systems, advanced load flow analysis, VVO, overhead and underground automated feeder reconfiguration,	Docket No. 15-122

		advanced sensing, and communications. The DPU did not preauthorize investment in remote circuit fault indicators for Eversource and did not approve its proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments (Grid Modernization Factor), which will include both capital investments and incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investment plans and five-year strategic plans, will be due by July 1, 2020. In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. A technical conference on performance metrics was held in February 2019. The utilities filed revisions to the grid modernization annual report template in February 2019. In February 2019, the DPU issued an order on the utilities' joint motion for clarification and/or reconsideration, clarifying the years that the utilities' investment plans and strategic plans should cover and extending the date for submitting the annual grid modernization filing, including actual project cost documentation. In early April 2019, the utilities filed revised performance metrics. The statewide metrics include increase in substations with distribution management system power flow and control capabilities, control functions implemented by circuit, number of customers benefitting from distribution automation devices, impact on outage duration and frequency, and a variety of metrics related to volt var optimization.	
Fitchburg Gas and Electric Light Company d/b/a Unitil	AMI, Smart Grid	In accordance with the Department of Public Utilities' June 2014 order on grid modernization plans, Unitil filed its grid modernization plan in August 2015. Unitil's proposed plan includes five programs: (1) DER enablement, (2) grid reliability, (3) distribution automation, (4) customer empowerment, and (5) workforce and asset management encompassing 16	Docket No. 15-121

		capital investment projects. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment proposals, finding that statewide deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $4.4 million for Unitil, which includes investments in an enterprise mobile damage assessment tool, outage management system integration with AMI, a field area network, VVO, SCADA, an advanced distribution management system, and a DER analytics visualization platform. The DPU did not preauthorize investments in Unitil's workforce mobility tool or 3V0 deployment. The DPU also did not approve Unitil's proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments, which will include both capital investments and incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investment plans and five-year	

		strategic plans, will be due by July 1, 2020. In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. A technical conference on performance metrics was held in February 2019. The utilities filed revisions to the grid modernization annual report template in February 2019. In February 2019, the DPU issued an order on the utilities' joint motion for clarification and/or reconsideration, clarifying the years that the utilities' investment plans and strategic plans should cover and extending the date for submitting the annual grid modernization filing, including actual project cost documentation. In early April 2019, the utilities filed revised performance metrics. The statewide metrics include increase in substations with distribution management system power flow and control capabilities, control functions implemented by circuit, number of customers benefitting from distribution automation devices, impact on outage duration and frequency, and a variety of metrics related to volt var optimization.	
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	AMI, Smart Grid	In accordance with the Department of Public Utilities' June 2014 order on grid modernization plans, National Grid filed its grid modernization plan in August 2015. National Grid proposed four different scenarios (Balanced Plan Scenario, AMI-Focused Scenario, Grid-Focused Scenario, and Opt-In Scenario) which provide a different portfolio of investments. The plans include investments in the following: AMI, customer load management devices, voltage optimization and conservation voltage reduction technologies, advanced distribution automation, feeder monitors, an advanced communications network, an advanced distribution management system and distribution supervisory control and data acquisition system, information and operational technologies, cybersecurity infrastructure and protocol development, training and asset management, and marketing outreach and education surrounding these technologies and new proposed offerings. The DPU issued an order in May 2018, denying the distribution utilities' AMI deployment proposals, finding that statewide	Docket No. 15-120

			deployment of AMI could result in stranded costs of $210 million, due to the current widespread deployment of AMR meters. The DPU notes that it believes AMI is still necessary to achieve its grid modernization objectives and that it will work with stakeholders to determine the best way to cost-effectively deploy AMI. The DPU will work to evaluate whether targeted AMI deployment to certain customer groups, such as new net metering or electric vehicle customers, is cost-effective. The order reduces the time period for preauthorization of grid modernization investments from five years to three years, with the distribution utilities being required to file three-year short term investment plans rather than five-year plans going forward. The order also reduces the time period for the utilities' strategic grid modernization plans from ten years to five years. The utilities are also to integrate cybersecurity concerns related to grid modernization into their existing planning processes. The DPU approved a three-year budget of $82 million for National Grid, which includes investments in VVO, advanced distribution automation, feeder monitors, communications and information/operational technologies, and advanced distribution management systems/SCADA. The DPU did not approve the company's proposed research and development projects. The DPU approved a short-term targeted cost recovery mechanism for the grid modernization investments, which will include both capital investments and incremental O&M investments. The DPU also determined that approved grid modernization costs will be recovered through a volumetric rate. Within 90 days of the order, the companies are to file a joint proposed evaluation plan for the three-year investment term. The next grid modernization filings, including both three-year investment plans and five-year strategic plans, will be due by July 1, 2020.In August 2018, the utilities filed a model Grid Modernization Factor tariff and performance metrics. A technical conference on performance metrics was held in February 2019. The utilities filed revisions to the grid modernization annual

		report template in February 2019. In February 2019, the DPU issued an order on the utilities' joint motion for clarification and/or reconsideration, clarifying the years that the utilities' investment plans and strategic plans should cover and extending the date for submitting the annual grid modernization filing, including actual project cost documentation. In early April 2019, the utilities filed revised performance metrics. The statewide metrics include increase in substations with distribution management system power flow and control capabilities, control functions implemented by circuit, number of customers benefitting from distribution automation devices, impact on outage duration and frequency, and a variety of metrics related to volt var optimization.	
Cape Light Compact	Energy Storage	In late October 2018, Massachusetts' electric utilities filed their joint statewide electric and gas three-year energy efficiency plan, covering 2019-2021. As part of the plan, Cape Light Compact proposed an Enhanced Storage Incentive program, where the Compact would install 1,000 behind-the-meter battery storage systems at residential and small commercial buildings. The Compact would provide a 100% incentive for the batteries in exchange for dispatch rights over the warrantied life of the batteries. The Compact would dispatch the batteries on a daily basis during the summer and on a targeted basis during the winter. In January 2019, the Department of Public Utilities issued an order on the plan, rejecting the Compact's proposed energy storage program.	Docket No. 18-116
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	Energy Storage, Smart Grid	In November 2018, National Grid filed a general rate case, which includes a proposed Phase II Electric Vehicle Market Development Program and an Energy Storage Program. The storage program would deploy up to 14 MW / 56 MWh of energy storage demonstration projects over five years to demonstrate the value of storage for solving distribution needs, improving system performance during peak usage periods, integrating renewable energy, and improving service quality. The proposed budget for the energy storage program is $50 million and National Grid	Docket No. 18-150

			would recover the costs through its Grid Modernization Recovery Provision. The utility also requested cost recovery for several IT projects, including technology modernization and cybersecurity. The proposed IT Technology Modernization Program involves modernizing critical applications to deliver new capabilities and updating operational technology networks to enable distribution automation, monitoring, and metering. Several parties filed testimony in March 2019. Tesla recommends approval of the storage program, and the Northeast Clean Energy Council recommends modifications to the screening and procurement process for non-wires alternatives, prohibition of utility ownership of behind-the-meter energy storage (until there is a demonstrated market failure in deployment of behind-the-meter storage in the state), and limiting utility procurement of storage to front-of-the-meter deployment that uses a competitive bidding process. Evidentiary hearings are scheduled for April 29, 2019 to May 24, 2019.	
	IOUs	Smart Grid	H. 3667 requires the Department of Public Utilities to direct utilities to proactively upgrade the distribution grid to improve reliability, resiliency, and customer access to DG and energy storage.	H. 3667 (I)
MD	IOUs	Energy Storage	H.B. 650 and S.B. 573 require the Commission to establish an Energy Storage Pilot Program. The pilot program will require each investor-owned utility to solicit offers to develop energy storage projects for each of the following commercial and regulatory models: utility-owned, utility owned and third party-operated, third party-owned, and virtual power plant. The cumulative size of the pilot projects is to be between 5 and 10 MW, with a minimum of 15 MWh. Both bills passed the House and Senate.	H.B. 650 (P2) S.B. 573 (P2)
	Potomac Edison	Smart Grid	In its most recent rate case, filed in August 2018, Potomac Edison proposed investments in distribution automation equipment. The proposed budget for the new investments is approximately $10.7 million, which would be recovered through a new Electric Distribution Investment	Docket No. 9490

			Surcharge. The Commission established the procedural schedule in October, including direct testimony in November, rebuttal testimony in December, initial briefs and reply briefs in February 2019. Multiple parties, including the Office of People's Counsel (OPC), provided testimony in November 2018. On December 6th, the OPC filed revised testimony, which Potomac Edison objected to in a December 10, 2018 motion. In its motion, Potomac Edison argued that the OPC's revised testimony was filed after the deadline and included substantive revisions. The motion calls on the Commission to strike the OPC's revisions and asked for an expedited review of the motion. In December 2018, the Public Service Commission (PSC) denied Potomac Edison's motion to strike the OPC's revised testimony, as the PSC determined the revisions did not present new substantive positions but provide corrections. An order filed in March 2019 approved the Electric Distribution Investment Surcharge and the investment in distribution automation equipment.	
MI	DTE Electric	Demand Response, Energy Storage	On March 29, 2019, DTE Electric filed an application for approval of its Integrated Resource Plan (IRP). The IRP includes 11 MW of solar-plus-storage pilot projects and an increase in demand response programs to 859 MW by 2024. A prehearing conference was held in April 2019.	Docket No. U-20471
	Upper Peninsula Power Company (UPPCO)	AMI	In September 2018, as part of a general rate case, UPPCO proposed the deployment of advanced meters to all residential and small commercial customers in its service territory. The investment would total $15.6 million over 2018 and 2019. In testimony filed in February 2019, the Commission Staff recommended against allowing cost recovery for the AMI investment due to concerns about the bill impact on ratepayers. A proposal for decision is expected in June 2019, and a final order is expected in August 2019.	Docket No. U-20276
MN	IOUs	Energy Storage	H.B. 165 and S.B. 100, among other things, authorize utilities to undertake energy storage pilot projects and establish	H.B. 165 (I) S.B. 100 (P1)

			criteria for utilities to recover costs for investment in energy storage pilot projects.	
	IOUs	Energy Storage	H.B. 1833 and S.B. 2067 authorize utilities to petition the commission for an energy storage system pilot project.	H.B. 1833 (I) S.B. 2067 (I)
MO	Ameren Missouri	AMI, Energy Storage, Smart Grid	In June 2018, the Missouri Public Service Commission opened a docket to adjust Union Electric Company (Ameren Missouri)'s rates. This rate adjustment was made possible by the passage in June 2018 of S.B. 564, which allows for yearly rate adjustments for electric utilities outside of normal rate case proceedings, as well as a one-time adjustment for the recent federal tax legislation (which is the adjustment taking place in this docket). S.B. 564 also allows for a simplified expense recovery mechanism (referred to as Plant In-Service Accounting) for utilities not using the yearly rate adjustment system. The bill requires utilities using Plant In-Service Accounting to file a capital investment plan and spend 25% of this capital investment on grid modernization, of which only 6% (of the 100 total, not the 25) can be for smart meters. In February 2019, Ameren filed a five-year capital investment plan with the Missouri Public Service Commission. The plan includes a total of $6.3 billion in investment, of which $1 billion is for wind energy. Grid modernization investments in the plan include AMI deployment ($245 million), distribution automation and other smart grid technology at the distribution level ($142 million), and distributed solar with energy storage ($89 million). Ameren made a presentation regarding its investment plan at the Commission's meeting on March 6, 2019.	Docket No. ER 2018-0632
MS	Entergy Mississippi	Demand Response, Energy Storage	In July 2018, Entergy Mississippi proposed a new Smart Energy Services program. Smart Energy Services is intended to broadly encompass energy efficiency and demand response, distributed solar, community solar, battery storage, distributed back-up generation, home energy services, and new billing options. Under the proposed program, Entergy would offer these various services to customers and recover costs in the	Docket No. 2018-UA-133

			manner it recovers supply-side resource investments. Entergy notes that one of the major drivers behind its proposed program is to expand access to these types of services to low-income customers. Entergy filed supplemental testimony in November 2018 and February 2019.	
NC	Duke Energy	Energy Storage	In September 2018 Duke Energy Carolinas and Duke Energy Progress filed their 2018 integrated resource plans, which span a 15-year horizon. Duke Energy Carolina's plan accounts for 4,059 MW of new resources, with natural gas accounting for 54% of the capacity additions, renewables and demand-side management accounting for 40%, and pumped and battery storage accounting for 6%. Duke Energy Progress's plan includes 6,300 MW of new resources, with natural gas accounting for 77% of the capacity additions, renewables and demand-side management accounting for 21%, and storage accounting for 2%. Numerous parties filed comments on the Integrated Resource Plans in early March 2019, including the Attorney General's Office, which argued for a greater consideration of renewables and energy storage. Additionally, six members of the NC General Assembly filed comments and requested a public hearing in Western North Carolina.	Docket No. E-100 Sub 157
	Duke Energy Progress	Energy Storage, Microgrid	In October 2018, Duke Energy Progress filed an application for a Certificate of Public Convenience and Necessity for its Hot Springs Microgrid Solar and Battery Storage Facility. The project would include 4 MW of lithium-based battery storage facilities. The cost estimate for the project has been redacted from the filing. As the Commission did not receive any significant protest regarding the project, it canceled the public witness hearing scheduled for January 23, 2019. The Public Staff filed testimony in late January. The Public Staff cited concerns it has about accurately quantifying the cost effectiveness of the project, but ultimately recommended Commission approval. In its testimony, the Public Staff also recommended certain reporting requirements and urged the Commission	Docket No. E-2 Sub 1185

		to require a study performed either by a third party or by Duke Energy to estimate the ancillary service benefits battery storage can provide Duke's system, using sub-hourly modeling techniques. In February 2019, Duke Energy, the Public Staff, and the North Carolina Sustainable Energy Association filed a joint motion to cancel the expert witness hearing previously scheduled for February 25, 2019. The motion states that there have been a number of statements of consumer support filed and no protests. Additionally, the joint motion states that Duke has agreed to the recommended conditions set forth by the Public Staff. The Commission followed with an order formally canceling the hearing. Duke Energy Progress and the Public Staff filed a joint proposed order in March 2019. The proposed order would approve the project subject to certain conditions, including reporting requirements and a requirement that Duke Energy conduct a study of the ancillary service benefits of battery storage using sub-hourly modeling techniques.	
Duke Energy Carolinas	Energy Storage, Smart Grid	In Duke Energy Carolinas' latest general rate case, filed in August 2017, the utility requested cost recovery for certain grid investments as part of its 10-year, $13 billion Power/Forward Carolinas plan. These investments include AMI, a distribution management system, automated switches, and communications network upgrades. Across Duke Energy Carolinas and Duke Energy Progress, these four investment categories were expected to total approximately $2.4 billion. A June2018 Commission order approved many elements of the general rate case, but left open many issues related Power/Forward. The order denied Duke's request for a new Grid Rider, and also asserted that this rate case is not the appropriate place to evaluate the prudency of the company's Power/Forward investments. Existing dockets (such as Integrated Resource Planning and Smart Grid Technology Plans), as well as future general rate case proceedings, will provide opportunities for the Commission to consider Power/Forward. However, since Duke did	Docket No. E-7 Sub 1146 Power/Forward Carolinas Stipulation Final Order

			not propose to recover AMI costs through the Grid Rider, the order approved Duke's request to recover $90.9 million for AMI deployment. A technical workshop regarding Duke Energy's revised grid investment plan (Grid Improvement Plan) was held on November 8, 2018. In December 2018, Duke filed a report on plans for AMI and Customer Connect-enabled rate design, pursuant to the Commission's June 2018 order. The report notes that Duke will evaluate a redesigned residential TOU rate, a residential fixed bill rate, a residential variable peak pricing rate, small commercial TOU and variable peak pricing rates, and large commercial/industrial TOU and variable peak pricing rates. Duke noted that it will file at least two pilots (one for residential customers and one for general service customers) at the time of its next rate case. In January 2019, Duke filed a report summarizing the November 2018 workshop on its Grid Improvement Plan, detailing stakeholder feedback. The new plan has a budget of approximately $2 billion. Duke Energy filed its revised AMI Rate Design Work Plan and Proposed Dynamic Pricing Pilots in early April 2019. The work plan includes a revised timeline to reflect accelerated implementation of the new Customer Connect billing system in Spring 2021.	
NH	Liberty Utilities	Energy Storage	In December 2017, Liberty Utilities filed an application to implement a battery storage pilot program, in which the utility will deploy 5 MW total of battery storage equipment at the homes of 1,000 residential customers. Participating customers would have control over the battery systems, except when a peak demand is predicted for the next day. The goal of the program is to reduce transmission costs and study potential benefits. The utility proposed inclusion of the battery costs in its rate base and applying a monthly charge to participating customers' bills. The utility is also requesting approval for a TOU rate for program participants, which includes	Docket No. 17-189

			critical peak, on-peak, and off-peak periods. Parties filed testimony in May 2018. A settlement agreement was filed in November 2018, which approves the program with modifications. Under the settlement, Liberty Utilities can deploy up to 500 Tesla PowerWall 2 batteries on customers' premises, with between 100 and 200 of these being in Phase I of the program. A working group will be established to develop a "Bring Your Own Device" program to deploy 500 additional batteries deployed by third parties. Customers will be able to have a battery installed for either an upfront payment of $2,433 or a monthly payment of $25 for 10 years. Net metering customers will not be able to charge their batteries from the grid, except when the batteries are under Liberty's control, but will receive credit for all energy exported to the grid, including that from the batteries. A hearing on the settlement was held in late November 2018. Sunrun and Revision Energy filed a closing statement in December, explaining their reasons for not signing onto the settlement agreement, but supporting Commission approval of it. In January 2019, the Commission issued an order approving the battery storage program as detailed in the settlement agreement. Before Phase I of the program may be implemented, Liberty Utilities must conduct a comprehensive evaluation of cybersecurity risks associated with the program. The order also directs Liberty Utilities to promptly inform the Commission, Staff, and parties if program costs are expected to be significantly more than estimated.	
NJ	PSE&G New Jersey	AMI	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Cloud Program includes deployment of AMI throughout PSE&G's service territory (2.2 million meters), with $721 million in investment and $73 million in operations and maintenance over five	PSE&G Regulatory Filings (Docket No. EO18101115)

		years. In total, the program will include 70 applications for the AMI, including 22 in the initial phase of the program the utility is currently seeking approval for. These applications, or use cases, include enhanced customer engagement and communications; a rate analyzer and comparator; usage and bill alerts, savings tips, and interactive bill presentment; interactive energy demand and bill management; customer segmentation and behavioral analysis; customer power quality; customer energy efficiency programs; customer service and call center performance; customer DER assistance and power quality management; customer device safety; sensor, network, and data operations; automated move-in/move-out; remote disconnect/reconnect; next generation meter-to-cash; network connectivity analysis; outage detection and analysis; outage response notification; voltage monitoring and analysis; asset load/phase management, balancing and power analysis; load profiling and forecasting; distribution losses; and revenue protection and assurance. PSE&G estimates that the program will provide $937 million in net benefits. PSE&G currently has AMR meters installed, and notes that 700,000 of its meters need to soon be replaced. PSE&G proposed semi-annual base rate adjustments to recover costs associated with the Energy Cloud Program. PSE&G is also seeking to defer as a regulatory asset the stranded costs of traditional meters not fully depreciated (about $219 million).	
PSE&G New Jersey	Energy Storage	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Electric Vehicle and Energy Storage Program includes deployment of 35 MW of energy storage, with $109 million in investment over six years and $70 in ongoing expenses over the 15-year life of the systems. Within the program, 10	PSE&G Regulatory Filings (Docket No. EO18101111)

		MW will be used for solar smoothing (5 installations for $13.1 million), 13 MW will be used for distribution deferral (7 installations for $38.6 million), 6 MW will be used for outage management (6 installations for $20 million), 2 MW will be used for microgrids for critical facilities (1-4 installations for $25.7 million, including 4 MW of solar), and 4 MW for peak reduction for public sector facilities (4 installations for $11.9 million). PSE&G proposed a decoupling mechanism in its current general rate case, and noted in the Clean Energy Future filing that if the decoupling mechanism is not approved, the utility would be open to considering another form of decoupling or an annual lost revenue adjustment mechanism to address lost revenues due to the energy storage program. PSE&G proposed a new rider (Technology Innovation Charge) to recover the net revenue requirements associated with the energy storage and electric vehicle programs. The Technology Innovation Charge would be a per-kWh charge applied equally to all rate schedules. PSE&G filed supplemental testimony in January 2019.	
N/A	Microgrid	S.B. 713, introduced in January 2018, requires the Board of Public Utilities to establish a microgrid program for state agencies and local governments to equip critical facilities.	S.B. 713 (I)
Atlantic City Electric	Smart Grid	In February 2018, Atlantic City Electric filed a request for approval of a $338.2 million infrastructure investment program over 2019-2022 to support and enhance distribution system reliability, resiliency, and safety. The proposed investments fall into five categories: targeted reliability improvement ($66.3 million), distribution automation/telecom ($93.1 million), infrastructure renewal ($103.2 million), emergency ($46.2 million), and facilities ($29.3 million). The distribution automation category includes grid modernizing investments, including automatic sectionalizing and restoration schemes and telecommunications investments to support distribution automation. The utility also proposed a new rider as a cost recovery mechanism for the investments. Public comments	ACE Infrastructure Investment Program Proposal (Docket No. EO18020196) ACE Rate Case Application (Docket No. ER18080925)

		hearings were held in July 2018. Atlantic City Electric filed a general rate case in August 2018, which includes requests for cost recovery for some of the infrastructure investment program costs. The utility noted that to the extent any investments are granted in either case, they will be removed from the other.	
Jersey Central Power & Light	Smart Grid	In July 2018, Jersey Central Power & Light (JCP&L) filed a four-year infrastructure plan called *JCP&L Reliability Plus* with the Board of Public Utilities. The proposal includes investments in four categories: overhead circuit reliability and resiliency ($132.9 million), substation reliability enhancement ($85.9 million), distribution automation (108.4 million), and underground system improvements ($59.7 million). The total budget for the proposal is $386.8 million over four years. Projects in the overhead circuit reliability and resiliency category include lateral fuse replacement, enhanced vegetation management, back-up generator installation. Projects in the substation reliability enhancement category include flood mitigation, substation equipment replacement, mobile substations, replacement of relays with new technology, and substation fencing enhancement. Projects in the distribution automation category include circuit protection and sectionalization, installation of SCADA-line devices, construction of loop schemes with reclosers and SCADA control, implementation of an advanced distribution management system, and installation of load voltage and data monitoring points with remote terminal unit upgrades. Projects in the underground system improvements category include underground cable replacement, submersible transformer replacement, and conventional and network rehabilitation. JCP&L proposed a new cost recovery mechanism for these investments, Rider RP - JCP&L Reliability Plus Charge.	JCP&L Application (Docket No. EO18070728)
PSE&G New Jersey	Smart Grid	In September 2018, PSE&G New Jersey filed its proposed Clean Energy Future plan, including investments in energy efficiency, electric vehicles, energy storage, and AMI. The Board of Public Utilities directed PSE&G to make separate	PSE&G Regulatory Filings (Docket No. EO18101113)

			filings for each of its proposed Clean Energy Future programs, which the utility filed in October 2018. The Clean Energy Future - Energy Efficiency Program includes a variety of customer-focused programs, including a Volt VAR Pilot Program, which will test smart grid technologies to control circuit voltage and reactive power on the distribution grid in order to reduce energy consumption, peak demand, and system losses, as well as to enable more solar deployment. PSE&G plans to hire a third-party contractor to install the hardware and software upgrades. The proposed budget for the Volt VAR Pilot Program is about $16.3 million. PSE&G proposed recovering the costs of its Clean Energy Future - Energy Efficiency Program through a new component of the Green Program Recovery Charge.	
NV	NV Energy	Energy Storage	In January 2019, NV Energy issued an open-source RFP for long-term firm capacity and energy resources. The RFP allows bidders to propose standalone energy storage systems with a minimum capacity of 25 MW over four hours. Bids were due on February 11, 2019. NV Energy plans to execute contracts with winning bids on April 11, 2019.	NV Energy RFP
NY	Niagara Mohawk Power Corporation d/b/a National Grid	AMI	In November 2018, National Grid released a report laying out its proposed deployment of AMI infrastructure. This report followed a stakeholder proceeding, which was called for in a settlement agreement in National Grid's last rate case approved in March 2018. The report calls for $446.35 million in AMI investments. Multiple parties filed comments opposing AMI deployment in early March 2019.	Case No. 17-G-0239
	PSEG Long Island	AMI	In June 2018, PSEG Long Island filed an annual update of its 2014 Utility 2.0 Long Range Plan. The update lays out plans for full AMI deployment in PSEG's service territory to take place from 2019-2022. Several parties filed comments on the plan during Q3 2018; only the New York Power Authority (NYPA) specifically addressed the AMI deployment, which it generally supported. NYPA also encouraged PSEG to prioritize public	Case No. 14-01299

		customers (and larger customers in general) for AMI deployment.	
IOUs	AMI, Smart Grid	A.B. 185, introduced in January 2019, requires utilities to develop smart grid deployment plans if, following a study, it is determined that smart grid deployment is in the public interest. The program is to include many components, including transmission and distribution system improvements, low-income assistance and education, access to real-time pricing data, AMI opt-out, opportunities for the use of smart appliance and plug-in or hybrid vehicles. Utilities are to invest in smart grid deployment if the studies determine that doing so is in the public interest. The bill notes that as part of this deployment, utilities must allow any customer to decline AMI installation at no fee. The bill also directs LIPA, NYPA, and rural electric cooperatives to develop grid modernization programs.	A.B. 185 (I)
IOUs	Energy Storage	In December 2018, the New York Public Service Commission (PSC) adopted an energy storage target and roadmap for deploying 1,500 MW of energy storage by 2025 and 2,000 MW by 2030. The roadmap contains provisions requiring utilities to competitively procure and have in operation certain amounts of energy storage capacity by the end of 2022. The required amount is 300 MW for Con Edison and 10 MW for each of the other investor-owned utilities (Central Hudson Gas & Electric, New York State Electric & Gas, National Grid, Orange & Rockland, and Rochester Gas & Electric). The utilities filed implementation plans for developing their competitive direct procurement programs in early February 2019.	Docket No. 18-00516/18-E-0130
Consolidated Edison	Energy Storage, Smart Grid	On January 31, 2019, Consolidated Edison (ConEd) filed a general rate case. In the rate case, ConEd proposes installing 31.5 MW of distribution-connected energy storage and six non-wires solutions projects, as well as deployment of communications infrastructure alongside the existing smart meter roll-out. A technical and procedural conference is scheduled was held in March 2019.	Docket No. 19-E-0065

OH	Dayton Power & Light	AMI, Energy Storage, Microgrid, Smart Grid	In December 2018, Dayton Power & Light (DP&L) filed its $866.9 million Distribution Infrastructure Modernization Plan. The plan includes AMI deployment; investments in advanced distribution infrastructure, communications equipment, and associated equipment; implementation of an online customer portal; and investments in physical and cyber security. Specifically, the utility plans to deploy automatic reclosers, smart switches, capacitor banks with controls, air break switch controls, single phase sensors to enable distribution automation and digital relays and communication gateways to enable substation automation. The utility is also planning to invest in an advanced distribution management system (ADMS) and will create a portal through which third parties can access information collected by the ADMS. DP&L also plan to invest in conservation voltage reduction, volt/var optimization, a GIS system, a mobile workforce management system, and telecommunications infrastructure. The plan also includes development of an Analytics Center of Excellence to analyze data from various devices and systems and a Computer Information System to enable new rate structures. DP&L also plans to install 50 electric vehicle charging stations and develop a community solar demonstration project, a battery storage demonstration project, and a microgrid program. DP&L plans to test four battery storage applications: strengthening reliability, peak shaving, peak shaving with provision of residential reliability benefits, and utility-scale deployment to reduce generation purchases. DP&L plans to offer an opt-in TOU rate option once the required information systems have been installed. DP&L is proposing to recover costs associated with the plan through its existing SmartGrid Rider with quarterly true-ups.	Docket No. 18-1875-EL-GRD
	Ohio Edison d/b/a First Energy	AMI, Smart Grid	In December 2017, First Energy filed a plan outlining a three-year $450 million investment in the modernization of its distribution network. The proposed projects include circuit ties, reconductoring, reclosers, and data acquisition systems. The utilities,	Docket No. 17-2436-EL-UNC Stipulation

		Commission staff, and other parties filed a stipulation in November 2018 agreeing to an aggregate of $516 million in capital investment, including AMI, an advanced distribution management system, distribution automation, and integrated volt/volt-ampere reactive control. The stipulation also establishes a Grid Mod Collaborative Group to update stakeholders and receive customer input. Stakeholders and the utility would begin discussing the development of a Grid Mod II plan by June 2020. In February 2019, First Energy filed an application in a new proceeding (19-0361-EL-RDR) for a two-year extension of its Distribution Modernization Rider (Rider DMR). The Commission originally approved Rider DMR for three years in 2016 and it is due to expire at the end of 2019.	
Dayton Power & Light	Demand Response	In January 2019, Dayton Power & Light filed an application for approval of a residential demand response pilot program. The program would allow the utility to control the air conditioning loads of participating customers through smart thermostats. Dayton Power & Light requested a start date for the program of May 1, 2019. The Ohio Consumers' Counsel filed an objection to the proposed program in April 2019.	Docket No. 19-0334-EL-UNC
Duke Energy Ohio	Energy Storage	Duke Energy Ohio filed its Electric Security Plan in June 2017. Part of its plan includes a proposal for a 10 MW pilot distribution battery storage system to be located in its southwest Ohio service territory. Duke also requested approval for a new rider mechanism to recover costs associated with PowerForward grid modernization efforts. Duke Energy filed a stipulation with a number of parties in April 2018 which recommends approval of the Electric Security Plan. In December 2018, the Commission merged several rate proceedings relevant to Duke Energy into a single docket. The Commission in its order allowed the battery storage project to go move forward as a pilot project. Duke Energy is required to file its application detailing the battery storage project in a separate proceeding. The order also approved the proposed tariffs, and Duke Energy will be filing the final	Docket No. 17-1263-EL-SSO

			tariffs for approval. Several parties filed applications for rehearing in January 2019. Duke Energy filed a memorandum contra applications for rehearing, but the Commission granted the applications for rehearing in February 2019.	
	Ohio Edison d/b/a First Energy	Smart Grid	In October 2016, the Public Utilities Commission of Ohio (PUCO) ordered First Energy to file a Distribution Modernization Rider (DMR), which would collect $600 million over three years to fund modernization of the distribution grid. First Energy filed its tariff in November 2016, and in December the Public Staff recommended its approval. The Ohio Consumers' Counsel (OCC) and the Ohio Manufacturers' Association Energy Group (OMAEG) then filed a joint motion to reject the DMR tariff. PUCO denied the consumer groups' motion and approved the DMR tariff in December 2016. The OCC filed an additional application for rehearing in January 2017, which PUCO denied in February 2017. PUCO issued its Eighth Entry for Rehearing in August 2017, which directs staff to work with a consultant to review how FirstEnergy uses the money collected under the DMR tariff. FirstEnergy filed an application for rehearing, arguing that the additional review is not necessary. In an October 2017 order, PUCO denied FirstEnergy's application for rehearing. In November 2017, the OCC filed an appeal with the Ohio Supreme Court to overturn the PUCO order granting approval for the DMR. Parties filed merit briefs with the Ohio Supreme Court during Q1 2018 and reply briefs during Q2 2018. Oral arguments took place in January 2019.	Docket No. 14-1297-EL-SSO Supreme Court No. 17-1664
OK	Public Service Company of Oklahoma	Smart Grid	In September 2018, as part of a general rate case, Public Service Company of Oklahoma proposed several smart grid investments in the areas of system automation, comprehensive system monitoring and analytics, power quality and reliability monitoring, and grid security. The investments in smart grid technologies would total $35 million annually. A settlement agreement was filed in late February 2019, which does not include cost recovery for grid modernization. A Distribution Reliability	Docket No. PUD 201800097 Press Release Order No. 692809

			and Safety Rider would provide for $5 million per year in distribution investments. The settlement agreement was approved on March 14, 2019.	
OR	Portland General Electric	Energy Storage	H.B. 2193 of 2015 directed utilities serving 25,000 or more residential customers to procure one or more energy storage systems with the capacity to store at least 5 MWh of electricity. The bill also directed the Public Utility Commission (PUC) to adopt guidelines for utilities to use in submitting an energy storage proposal. The PUC initiated a proceeding in September 2015, and issued an order adopting guidelines in December 2016. The guidelines cover various topic areas, including how utilities can design and select projects to propose, how utilities should submit their formal proposals, storage evaluation requirements, and competitive bidding requirements. The PUC order also directed the Commission Staff to convene workshops to develop a framework for the utilities to use in conducting storage potential evaluations. The Commission Staff submitted its recommendations in March 2017, which the PUC later approved. Portland General Electric and Pacificorp each submitted their Draft Storage Potential Evaluations, and the PUC opened an informal comment period running through August 25, 2017. The Commission Staff found deficiencies in both utilities' evaluations, and submitted a report to the PUC with a number of recommended changes and improvements. The Commission Staff also recommended giving the utilities until January 1, 2018 to resubmit their drafts and April 2, 2018 to submit final drafts. The PUC approved the recommendations in a September order, and the utilities filed their revised storage potential evaluations during Q4 2017. Portland General Electric submitted a partial settlement and stipulation with several parties in May 2018, which included plans for five pilot energy storage projects and one microgrid project. The Commission approved the stipulation and resolved the one remaining issue not addressed in the stipulation in August 2018. Portland General Electric filed revisions to its residential storage pilot project in January 2019, as required	[Docket No. UM 1856]

			by the stipulation. The revised pilot aggregates and dispatches residential storage units as a single resource and includes enhanced data collection and program evaluation.	
RI	Narragansett Electric Company d/b/a National Grid	Energy Storage, Smart Grid	In December 2018, National Grid filed its Electric Infrastructure, Safety, and Reliability (ISR) plan for fiscal year 2020. The plan includes categories for spending on electric infrastructure, operation and maintenance, vegetation management, inspection and maintenance, and volt/var optimization and conservation voltage reduction (VVO/CVR) expansion. The bill impact from proposed project will result in monthly bill increase of $0.79 for a customer using 500kWh a month. The plan also includes an energy storage proposal for 250 kW / 2 hour behind-the-meter energy storage to support electric vehicle charging to be completed by the end of 2019, and 500 kW /3-hour front-of-the-meter energy storage for grid support to be completed by end of 2020.	Docket No. 4915
SC	Duke Energy	AMI, Energy Storage, Smart Grid	In Duke Energy Progress' and Duke Energy Carolinas' general rate cases, filed in November 2018, the utilities requested approval for its Grid Improvement Plan. The plan is broken into three categories: (1) compliance-driven programs to protect the grid, (2) programs using advanced technologies to modernize the grid, and (3) projects and programs to optimize the customer's experience. The plan includes investments in integrated volt/var control, a self-optimizing grid (advanced distribution management system, circuit segmentation and automation, upgrading circuits and tying them together, and upgrading substations), power electronics for volt/var, distribution system automation (replace hydraulic reclosers with electronic reclosers, system intelligence and monitoring pre-scale effort, replace fuses with electronic reclosers, and underground system automation), transmission system intelligence (system intelligence and monitoring, replace electrochemical and solid state relays with digital relays, enable remote substation monitoring, and replace non-communicating switches with SCADA and remote control enabled switches), AMI, and energy storage	Docket No. 2018-318-E Docket No. 2018-319-E SC Grid Improvement Plan Budget Grid Improvement Plan

			(storage control system). The plan also includes distribution transformer retrofits, transmission bank replacement, oil breaker replacement, transmission hardening, flood hardening, targeted undergrounding, and reliability investments (hardening, circuit relocations, new circuit ties, undergrounding, energy storage) at individual sites with high potential for long duration outages with high impact. The plan also includes developing an Integrated System Operations Planning (ISOP) process that will integrate generation, transmission, distribution, and customer program planning, as well as a data access program that will integrate customer data with Green Button. The plan also includes physical security and cybersecurity investments, including fencing, lighting, intrusion detection technology, replacing Windows-based relays with devices to operate in a Linux environment, firewalls, replacement of vulnerable devices, and EMP protection. The plan also includes electric transportation programs that have been proposed by the utility in a separate proceeding. The three-year total budget for the plan is about $455 million for the two utilities. The Office of Regulatory Staff filed a motion to consider the Grid Improvement Plan in its own proceeding, then later filed a stipulation with Duke Energy for the same request.	
UT	Rocky Mountain Power	AMI, Energy Storage, Smart Grid	In November 2018, Rocky Mountain Power requested approval to allocate an additional $1.75 million in STEP Act program funding to the Solar and Storage Technology Project. A hearing was held in January 2019, and the Commission approved the funding increase in February 2019. In March 2019, Rocky Mountain Power filed an application to implement additional programs as part of the Sustainable Transportation and Energy Plan (STEP) Act programs. The utility proposed three new programs: (1) the Power Balance and Demand Response to Optimize Charging at Intermodal Hub Project, (2) the Wasatch Development Partnership Project for Battery Demand Response, and (3) the Advanced Resiliency Management System Project.	Docket No. 16-035-36

			The Battery Demand Response program involves Rocky Mountain Power installing individual batteries in each unit of a 600-unit multi-family development that has not yet been constructed. The batteries would be charged by solar, and the utility would have control over the batteries. The budget for the Battery Demand Response program is $3.27 million. The Advanced Resiliency Management System Project involves the utility installing encoder receiver transmitter electric meters (automated meter reading, or AMR), communication radios on distribution line equipment, and additional line sensor technology. The Advanced Resiliency Management System Project budget is $16.52 million. A technical conference was held in early April 2019, and a hearing is scheduled for June 17, 2019.	
VA	Appalachian Power Co.	AMI, Smart Grid	In December 2018, Appalachian Power filed for approval of a plan for electric distribution grid transformation projects as part of the 2018 Grid Transformation and Security Act (S.B. 966). The plan includes a proposal to incorporate Appalachian Power's existing program of replacing distribution assets that are at the end of their useful lives with infrastructure that facilitates the integration of DERs or enhances the reliability and security of the grid. The plan includes continued replacement of Automated Meter Reading (AMR) equipment, with a goal of replacing all of the meters in its service territory by the end of 2022. Other plans include asset improvement projects, a grid automation project, vegetation management, and distribution grid security and cyber security projects. In February 2019, Appalachian Power filed a motion for leave to file supplemental direct testimony which focuses on AMI. The commission granted the motion. Appalachian Power filed a motion for leave to withdraw its petition in March 2019. The motion cites the fact that the Commission's January 2019 order on Dominion's petition established several requirements for future petitions for grid transformation projects. In light of these requirements, Appalachian Power wants to withdraw its current petition and re-file a new petition using the Commission's guidance from the	Docket No. PUR-2018-00198

			Dominion order. The Commission granted the motion.	
	Dominion Virginia Power	AMI, Smart Grid	Dominion filed a Petition for approval of Phase 1 of its Grid Transformation Plan. Phase 1 covers the first three years of the ten-year plan, and has an estimated cost of $816.3 million with an additional $101.5 million in operations and maintenance costs. The entire 10-year plan has a cost of $5.98 billion. The plan includes full deployment of smart meters throughout its service territory, reaching 1.4 million smart meters during Phase I (2019-2021) with an additional 600,000 installed during 2022-2023. The plan also includes the deployment of smart grid technologies, a customer information platform, grid resiliency measures, and physical and cyber security measures. The Commission is required to issue its final order on the Petition within six months of the filing date. The Commission filed an Order in July 2018 establishing the procedural schedule. Dominion filed extensive testimony in October and November 2018, and a hearing was held in November. In January 2019, the State Corporation Commission (SCC) issued a final order approving the Phase I costs for cyber and physical security ($35.2 million), and some telecommunications costs ($119.2 million) as reasonable and prudent. Over 10 years, the cyber and physical security cost would be $106.9 million and the telecommunications cost would be $803.4 million. Other costs for AMI ($523.8 million for Phase I / $824.4 million over 10 years), intelligent grid devices ($104.6 million for Phase I / $776 million over 10 years), and grid hardening ($486.1 million for Phase I / $3 billion over 10 years) were not approved. The SCC is open to Dominion re-filing more developed costs and plans for proposals that were not approved.	Docket No. PUR-18-00100
VT	Green Mountain Power	Energy Storage, Microgrid	In November 2017, Green Mountain Power filed a request for a Certificate of Public Good for its proposed MicroGrid-Milton Project. The proposed project is a microgrid, including a 4.99 MW solar facility and a 2 MW battery storage facility (2 MW/8 MWh Tesla Powerpack.) The estimated cost of the project is $13.4	Docket No. 17-5003-PET

			million. A hearing was held in mid-October 2018. The Commission issued a final order in February 2019, granting the Certificate of Public Good with certain terms and conditions.	
	Green Mountain Power	Energy Storage, Microgrid	In December 2017, Green Mountain Power filed a request for a Certificate of Public Good for its proposed MicroGrid-Ferrisburgh Project. The proposed project is a microgrid, including a 4.99 solar facility and a 2 MW battery storage facility (2 MW/8 MWh Tesla Powerpack.) The estimated cost of the project is $13.5 million. Later in December, the Public Utility Commission issued an order, finding the application incomplete. Green Mountain Power refiled its petition in March 2018, which the Commission found complete. An evidentiary hearing was held in early November. The Commission issued a final order in February 2019, granting the Certificate of Public Good with certain terms and conditions.	Docket No. 17-5236-PET
WI	Wisconsin Power & Light	Energy Storage	In February 2019, Wisconsin Power & Light filed an application for approval of three new renewable energy tariff options: a community solar program, a renewable energy partner program, and a customer-hosted renewables pilot program. The customer-hosted renewables program would provide customers with bill credits in exchange for hosting utility-owned renewable generation and/or storage systems, with a total of 35 MW of capacity to be hosted (10 MW is reserved for non-profit organizations). Customers would be eligible for monthly lease payments of $1,500 per MW for hosting standalone battery storage systems; the payment for solar-plus-storage systems would be based on MISO prices.	Docket No. 6680-TE-104

Legislative Status Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, D = Dead. Bill statuses are up to date as of mid-April 2019.

Q2 2019 OUTLOOK

Most state legislative sessions will continue into Q2 2019, with over 150 bills related to grid modernization still under consideration across the country. One state – **Louisiana** – began its legislative session in April 2019.

A bill introduced in Q2 2019 in **North Carolina** authorizes multi-year rate plans, while another bill addresses energy storage interconnection rules and extends an existing solar property tax abatement to storage projects.

The **California** Public Utilities Commission issued a proposed decision on Southern California Edison's grid modernization plan, which approves most elements of the plan but at lower budget levels than originally requested.

A workshop on Duke Energy's **North Carolina** Grid Improvement Plan is scheduled for May 2019, and a study on utility business models in **Hawaii** is expected to be published during Q2 2019.

Ohio's PowerForward working groups on data and distribution system planning both met in April 2019. A kickoff workshop for **Oregon**'s distribution system planning proceeding is scheduled for May 2019, as well as a workshop on development of performance incentive mechanisms in **Minnesota**.

The **Massachusetts** Department of Energy Resources presented its clean peak standard straw proposal in early April 2019, and the **New York** Public Service Commission issued a decision approving modifications to the Value of Distributed Energy Resources tariff.

In the **District of Columbia**, the MEDSIS working groups filed a report with their draft recommendations. The report includes many recommendations related to data, non-wires alternatives, rate design, customer impact, microgrids, and pilot projects.

Indiana Michigan Power filed its distribution system plan in **Michigan** in early April 2019. The plan $56 million over five years and includes investments in AMI and distribution automation. NV Energy filed its distributed resource plan in **Nevada** in April 2019 as well.

In **Rhode Island**, a draft grid modernization plan is expected to be shared in May 2019, following several months of work by the Power Sector Transformation Advisory Group. The **Tennessee** Valley Authority issued a request for proposals for 200 MWh of renewable energy with storage.

ENDNOTES

[1] Energy Storage Association, *Facts and Figures*, 2018, http://energystorage.org/energy-storage/facts-figures

[2] Adam Cooper, *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*, The Edison Foundation Institute for Electric Innovation, December 2017, http://www.edisonfoundation.net/iei/publications/Documents/IEI_Smart%20Meter%20Report%202017_FINAL.pdf