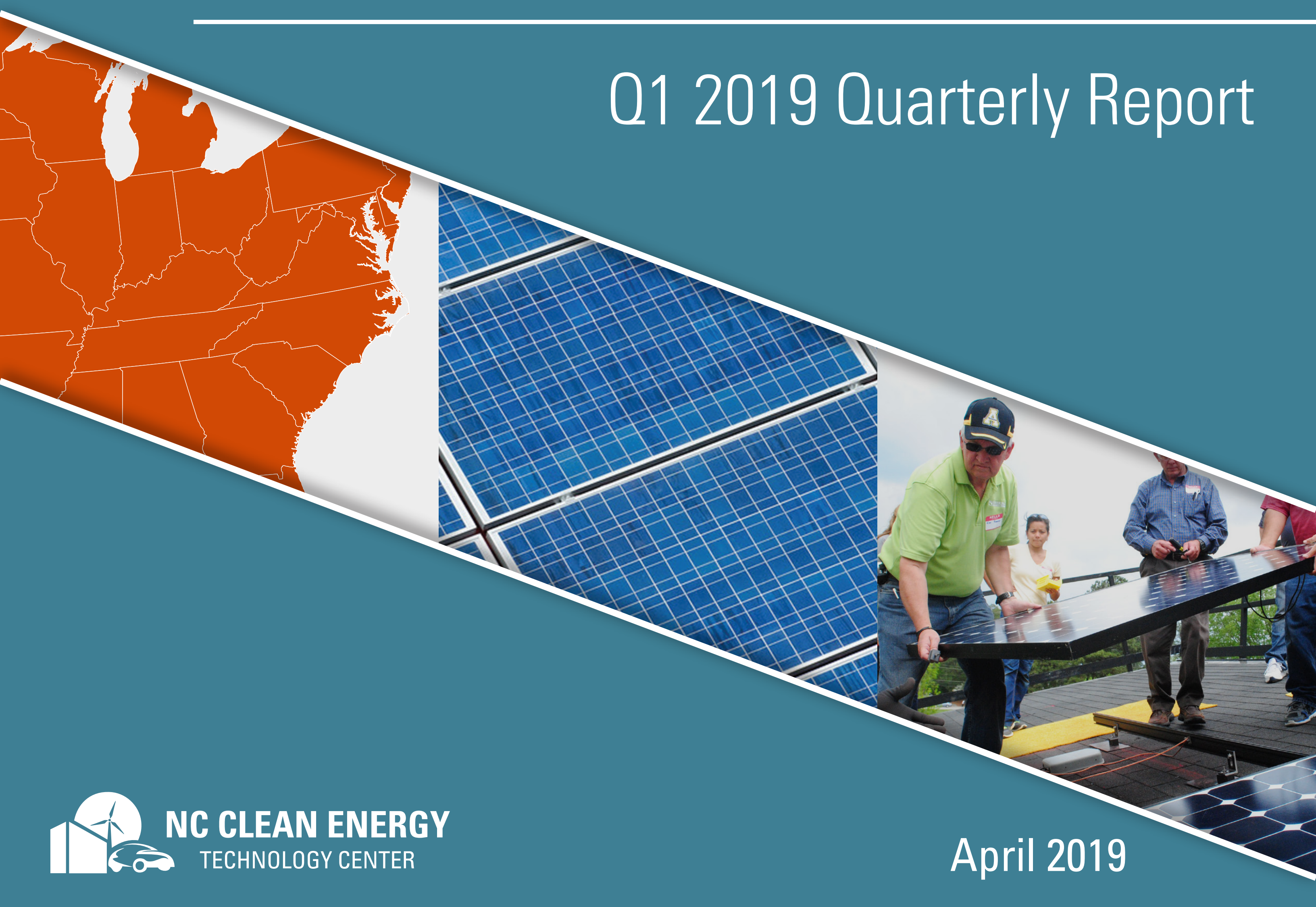
50 States of SOLAR

Q1 2019 Quarterly Report



NC CLEAN ENERGY
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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

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

The NC Clean Energy Technology Center also publishes the *50 States of Grid Modernization* and the *50 States of Electric Vehicles* on a quarterly basis. Executive summaries of these reports may be found here. Please contact us for older issues of the *50 States of Solar*.

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GLOSSARY OF ABBREVIATIONS

ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
d/b/a	Doing Business As
DER	Distributed Energy Resources
DG	Distributed Generation
IOU	Investor-Owned Utility
kW	Kilowatt
kWh	Kilowatt-Hour
MW	Megawatt
NEM	Net Energy Metering
PPA	Power Purchase Agreement
PV	Photovoltaics
REC	Renewable Energy Credit
RFP	Request for Proposals
TOU	Time of Use

OVERVIEW

PURPOSE

The purpose of this report is to provide state lawmakers and regulators, electric utilities, the solar industry, and other energy stakeholders with timely, accurate, and unbiased updates on state actions to study, adopt, implement, amend, or discontinue policies associated with distributed solar photovoltaics (PV). This report catalogues proposed and enacted legislative, regulatory policy, and rate design changes affecting the value proposition of distributed solar PV during the most recent quarter, with an emphasis on the residential sector.

The 50 States of Solar series provides regular quarterly updates of solar policy developments, keeping stakeholders informed and up to date on a timely basis.

APPROACH

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

Questions Addressed

This report addresses several questions about the changing U.S. solar policy landscape:

- How are (1) state legislatures and regulatory authorities and (2) electric utilities addressing fast-growing markets for distributed solar PV?
- What changes to traditional rate design features and net metering policies are being proposed, approved, and implemented?
- Where are distributed solar markets potentially affected by policy or regulatory decisions on community solar, third-party solar ownership, and utility-led residential rooftop solar programs?

Actions Included

This report series focuses on cataloguing and describing important proposed and adopted policy changes affecting solar customer-generators of investor-owned utilities (IOUs) and large publicly-owned or nonprofit utilities (i.e., those serving at least 100,000 customers). Specifically, actions tracked in these reports include:

- Significant changes to state or utility **net metering** laws and rules, including program caps, system size limits, meter aggregation rules, and compensation rates for net excess generation
- Changes to statewide **community solar** or **virtual net metering** laws and rules, and individual utility-sponsored community solar programs arising from statewide legislation
- Legislative or regulatory-led efforts to study the **value of solar**, **net metering**, or **distributed solar generation policy**, e.g., through a regulatory docket or a cost-benefit analysis
- Utility-initiated rate requests for **charges applicable only to customers with solar PV** or other types of distributed generation, such as added monthly fixed charges, demand charges, stand-by charges, or interconnection fees
- Utility-initiated rate requests that propose a 10% or larger increase in either **fixed charges** or **minimum bills** for all residential customers
- Changes to the legality of **third-party solar ownership**, including solar leasing and solar third-party solar power purchase agreements (PPAs), and proposed **utility-led rooftop solar** programs

In general, this report considers an "action" to be a relevant (1) legislative bill that has been passed by at least one chamber or (2) a regulatory docket, utility rate case, or rulemaking proceeding. Introduced legislation related to third-party sales is included irrespective of whether it has passed at least one chamber, as only a small number of bills related to this policy have been introduced. Introduced legislation pertaining to a regulatory proceeding covered in this report is also included irrespective of whether it has passed at least one chamber.

Actions Excluded

In addition to excluding most legislation that has been introduced but not advanced, this report excludes a review of state actions pertaining to solar incentives, as well as more general utility cost recovery and rate design changes, such as decoupling or time-of-use tariffs. General changes in state implementation of the Public Utility Regulatory Policies Act of 1978 and subsequent amendments, including changes to the terms of standard contracts for Qualifying Facilities or avoided cost rate calculations, are also excluded unless specifically related to the policies described above. The report also does not cover changes to a number of other policies that affect distributed solar, including solar access laws, interconnection rules, and renewable portfolio standards. Details and updates on these and other federal, state, and local government policies and incentives are available in the NC Clean Energy Technology Center's Database of State Incentives for Renewables and Efficiency, at **www.dsireusa.org**.

U.S. DISTRIBUTED SOLAR MARKET

The U.S. residential solar market was relatively flat over the course of 2018, and the majority of mature state markets saw flat or declining rates of new installations.[1] However, analysts anticipate overall growth in 2019, with 60% of the total new U.S. residential capacity installed between 2018 and 2023 predicted to be in California, Illinois, and Florida.[2] Growth is expected to slow for overall solar installations in the non-residential sector, although increased growth in community solar projects is expected.[3] In the first three quarters of 2018, 400 MW of community solar was installed, and analysts predict that by 2023, 30% of annual non-residential installations will be community solar projects.[4]

State Policy in Transition

State solar policy continues to be a source of uncertainty, as the majority of U.S. states consider reforms related to distributed generation compensation policies, solar ownership models, and rate structures. In 2018, state and utility solar policies were undergoing review in nearly every state in the country, with 47 states and DC considering changes in 2018. While just a few years ago dramatic changes to net metering policies were being discussed in only a handful of states, in 2018 major reforms were under consideration or already adopted in at least 22 states.

This increased attention to solar policy and rate design comes in response to a fundamental shift occurring in the U.S. electric system. The electric system in the U.S. has traditionally been a "one-way street", with power flowing from utility-owned centralized generation, via utility-owned transmission and distribution lines, toward end-use customers. However, the electric system is increasingly becoming more of an interconnected web, with small but growing numbers of end-use customers also generating electricity with small-scale, distributed systems, many of which are capable of providing various services to the grid. Because state policies and utility rate designs were developed around the former model, it is likely that this new model will necessitate significant changes to ensure fair market access and compensation for all grid participants.

State solar policies are increasingly being examined in a broader context, as part of comprehensive grid modernization efforts. A growing number of states are examining the future of the electricity system more holistically, considering various types of technologies, as well as policies, rate structures, and business models all at once. Policies once focusing on solar photovoltaics in particular are now often being considered with a broader set of distributed energy resources, including energy storage, in mind. These cross-cutting examinations are bringing together diverse stakeholders and leading to the consideration of innovative new solutions. Such comprehensive efforts by states are reviewed in a companion quarterly report series by the NC Clean Energy Technology Center, entitled *The 50 States of Grid Modernization*.

OVERVIEW OF Q1 2019 POLICY ACTION

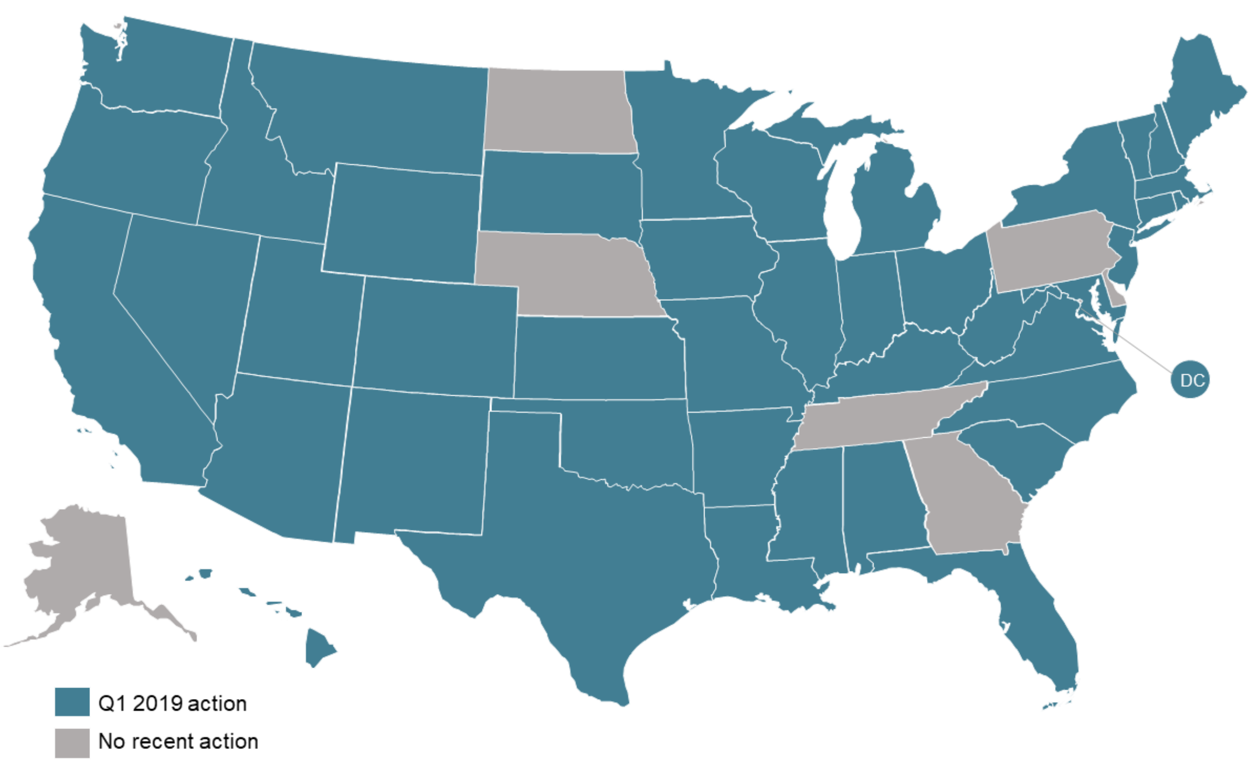
Table 1 provides a summary of state actions related to DG compensation, rate design, and solar ownership during Q1 2019. Of the 160 actions catalogued, the most common were related to DG compensation rules (47), followed by residential fixed charge and minimum bill increases (32), and community solar (25). The actions occurred across 43 states plus DC in Q1 2019 (Figure 1). Box 1 highlights some of the key actions of Q1 2019, described in greater detail in the following sections.

Table 1. Summary of Policy Actions (Q1 2019)

Policy Type	# of Actions	% by Type	# of States
DG compensation rules	47	29%	27 + DC, PR
Residential fixed charge or minimum bill increase	32	20%	20
Community solar	25	16%	18 + DC
DG valuation or net metering study	21	13%	17 + DC
Third-party ownership of solar	16	10%	10
Residential demand or solar charge	13	8%	9
Utility-led rooftop PV programs	6	4%	6
Total	**160**	**100%**	**43 States + DC, PR**

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

Figure 1. Action on Net Metering, Rate Design, & Solar Ownership Policies (Q1 2019)



Box 1. Top Five State Solar Policy Developments of Q1 2019

Maine State Legislature Restores Retail Rate Net Metering

The Maine State Legislature passed L.D. 91 in March 2019, which restores traditional retail rate net metering in the state and prohibits the buy-all, sell-all successor tariff adopted by the Public Utilities Commission in 2017. The Governor signed the bill in early April 2019, and the Commission opened an emergency rulemaking to amend the state's net metering regulations.

Kentucky Lawmakers Initiate Development of Net Metering Successor

Kentucky legislators enacted S.B. 100 in March 2019, directing the Public Service Commission to establish new monetary credit rates for energy exported to the grid. The bill also allows utilities to implement rates to recover fixed and demand-based costs of serving customer-generators. Customer beginning to net meter before the new credit rates are established will be grandfathered for 25 years.

Arkansas Legislature Legalizes Solar Leasing and Addresses Net Metering

Arkansas lawmakers enacted S.B. 145 in March 2019, which legalizes solar leasing, increases the net metering system size limit, and allows solar-plus-storage systems to net meter. The bill also requires utilities to offer retail rate net metering to DG customers that are subject to rates that include demand charges, and directs regulators to establish a netting period and credit rates for DG customers served on rates that do not include demand charges.

Colorado Regulators Open Rulemaking on Community Solar and Net Metering

The Colorado Public Utilities Commission opened a rulemaking in February 2019 addressing several of the state's electric rules, including community solar and net metering. The proposed rules include provisions related to net metering under time-of-use rates, installation of additional meters, and contribution of excess community solar credits for low-income energy assistance.

Sacramento Municipal Utility District Proposes Grid Access Charge

In March 2019, Sacramento Municipal Utility District proposed a new Grid Access Charge for customers with on-site generation. The charge would begin at $8.00 per kW of DG system capacity in 2020 and increase to $11.00 per kW by 2025. Existing systems would be grandfathered for a period of 10 to 20 years from the initial billing period after installation. SMUD withdrew the charge from consideration in mid-April 2019.

Box 2. Top State Solar Policy Trends & Insights of Q1 2019

State Legislatures Weigh in on DG Rate Design

Several state legislatures are considering bills either authorizing or prohibiting additional fees for DG customers. A bill enacted in Arkansas in March 2019 allows the Public Service Commission to establish a per-kWh fee to recover quantifiable, direct demand-related distribution costs from net metering customers, while a bill enacted in Virginia allows electric cooperatives to adopt demand charges for net metering customers. A bill pending in Iowa would establish four alternatives to the state's current net metering policy, one of which includes a minimum bill and one including a demand charge. On the other hand, bills pending in Kansas and Texas prohibit additional charges for DG customers. A Kentucky bill would have limited the types of costs that may be recovered through fixed charges, while a South Carolina bill takes a study approach, directing regulators to consider the cost of service impacts of customer-generators on other customers within the same rate class.

States Move in Different Directions on Net Metering

The first quarter of 2019 was characterized by states moving in very different directions regarding net metering. Kentucky lawmakers enacted a bill that will move the state to a net billing regime, while Maine legislators voted to restore net metering in the state after regulators adopted a buy-all, sell-all compensation framework in 2017. Arkansas also established certain guidelines for net metering successor tariff development, while other states, such as New Hampshire and Washington, moved forward bills that expand net metering by increasing system size limits or aggregate capacity limits. While many states are actively considering net metering successor tariffs, it is worth noting that two states that had previously adopted particularly dramatic policy changes – Maine and Nevada – have now reversed course and re-implemented traditional net metering.

New States Eye Community Solar Programs

A number of states without community solar enabling legislation considered major community solar bills during Q1 2019. Among these states are Florida, Nevada, New Mexico, Pennsylvania, and South Carolina. Each state's proposed legislation would establish community solar guidelines that allow participation by third-party developers. Notably, these bills all also include provisions to encourage participation by low-income customers, such as carve-outs. Low-income access is a program design consideration that is starting to become standard practice in community solar policy. The Michigan Public Service Commission is also conducting a stakeholder proceeding to consider barriers to third-party community energy projects in the state.

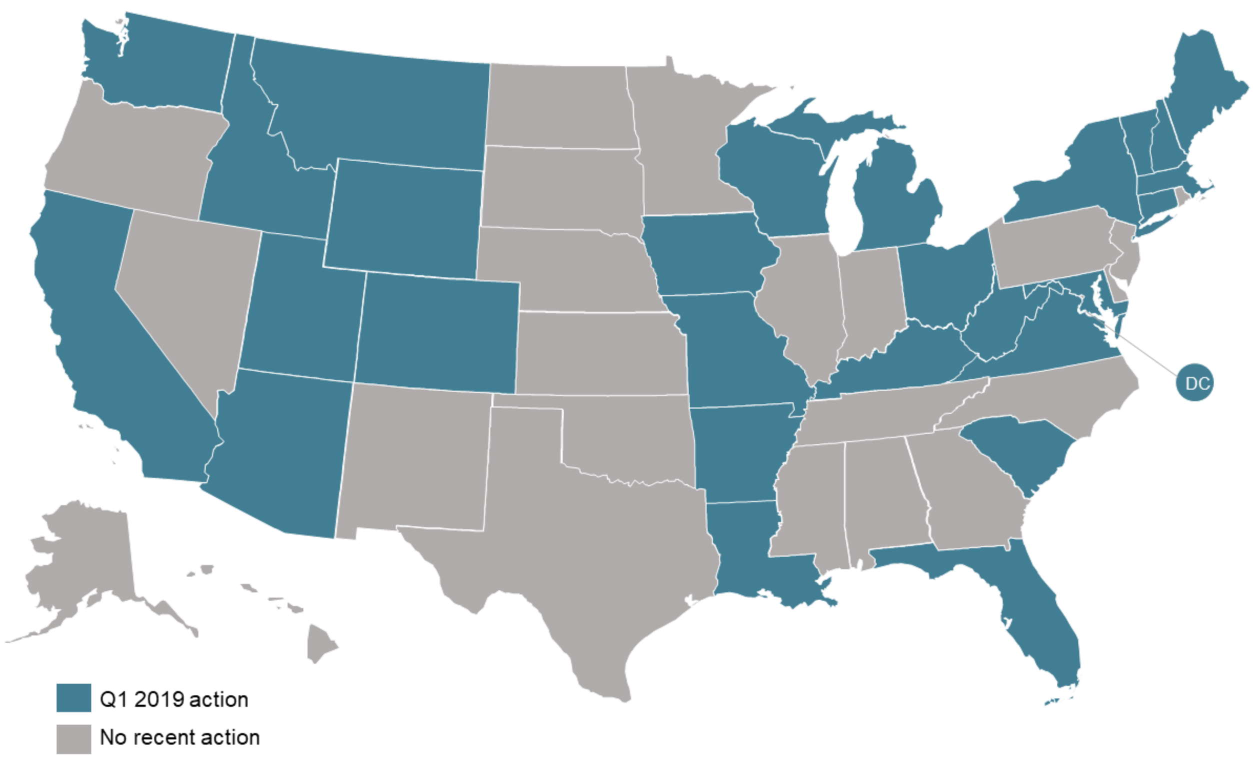
DG COMPENSATION POLICY CHANGES

Key Takeaways:

- In Q1 2019, there were 47 actions related to DG compensation policy changes ongoing or under consideration in 27 states plus DC and Puerto Rico.
- The Maine State Legislature enacted a bill restoring traditional net metering in the state.
- Lawmakers in Arkansas and Kentucky enacted legislation addressing net metering successor tariffs.

In Q1 2019, 27 states plus DC and Puerto Rico took actions related to distributed generation (DG) compensation policies. Of these, 15 states considered changes to credit rates for excess generation or the development of a net metering successor tariff.

Figure 2. Action on DG Compensation Policies (Q1 2019)

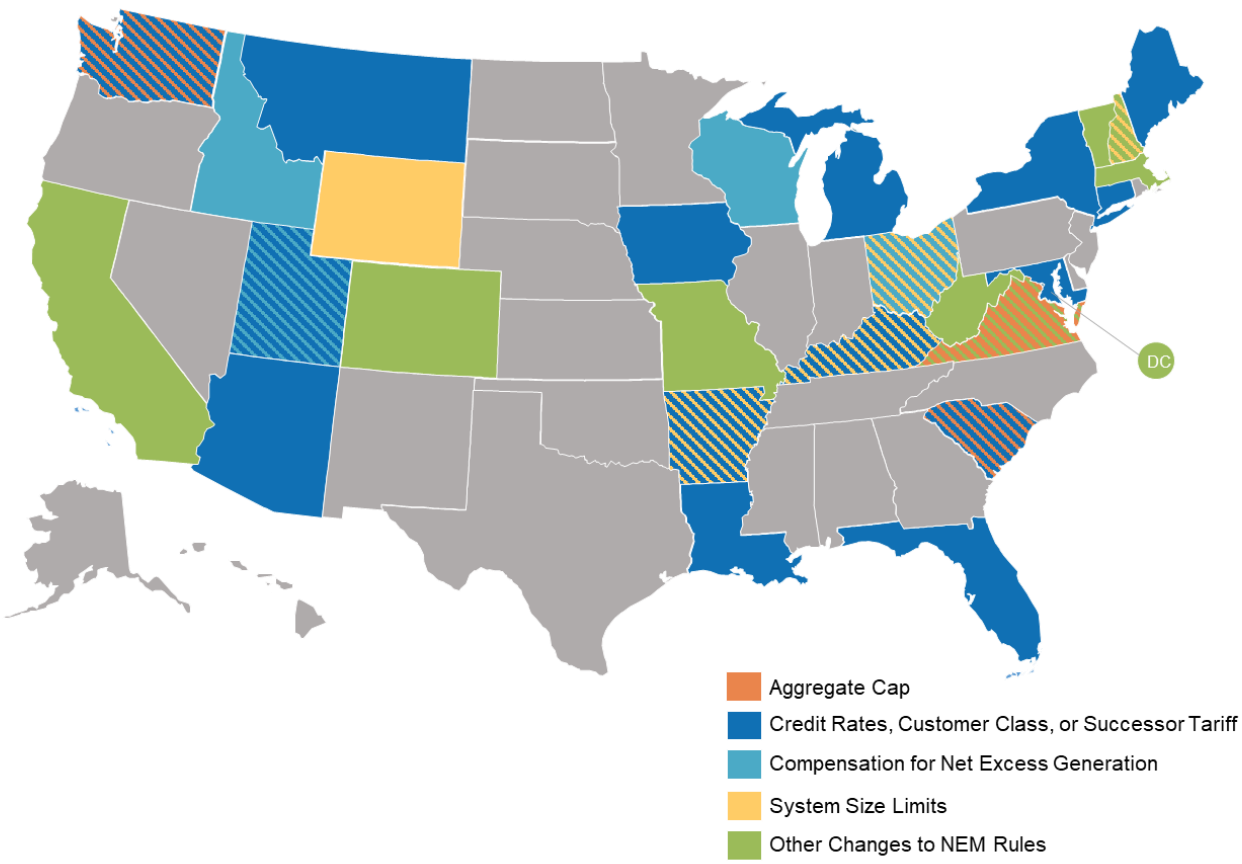


Net Metering Successor Tariffs

Several states considered bills during Q1 2019 that would establish net metering successor tariffs or otherwise make major changes to net metering policies. State legislatures in both Arkansas and Kentucky enacted bills addressing net metering successor tariffs, with Arkansas' bill providing certain guidelines for a successor tariff that the Public Service Commission may approve and Kentucky's bill taking a more direct approach, requiring regulators to establish new monetary credits for energy exported to the grid. Notably, Arkansas' bill also requires traditional net metering to be offered to customers served on rates including demand charges.

The South Carolina State House passed a bill in February 2019 requiring the Public Service Commission to establish a net metering successor tariff by May 31, 2021. A bill passed by the Iowa State Senate establishes four new options to replace the current net metering policy. These options include net metering with a minimum bill, net metering with a demand charge, a buy-all, sell-all program, and an open-ended cost of service based structure that a utility may propose. By contrast, Maine lawmakers enacted a bill restoring traditional net metering, departing from the state's buy-all, sell-all successor tariff adopted by the Public Utilities Commission in 2017.

Figure 3. Proposed and Adopted Changes to DG Compensation Policies, by Type of Change (Q1 2019)



Major renewable energy legislation passed in Puerto Rico during Q1 2019 had initially included provisions that could have led to changes in the territory's net metering policy. However, the final version of the legislation did not include these provisions; the bill instead requires utilities to continue with the current net metering rules for at least the next five years and guarantees that current net metering customers will be able to continue taking service under the existing rules for at least 20 years if policy does change following the five-year period during which net metering is required.

Tucson Electric Power (TEP) and UNS Electric in Arizona filed their pilot Time-of-Generation (TOG) tariffs during Q1 2019, pursuant to the Commission's decision on their DG rate design proposals and initial DG export rates. The pilot TOG tariffs take a buy-all, sell-all approach and compensate production with time-varying credit rates. These credit rates range from 7.59 (TEP) and 9.21 (UNS) cents per kWh during off-peak hours to 28 cents per kWh during on-peak hours.

Box 3. A Note on Net Metering Terminology

Credit rates refers to changes to compensation for all electricity exported to the grid, either instantaneously or netted over a period shorter than the billing period (e.g., 15-minute or 60-minute intervals.) **Net excess generation** includes changes to compensation for excess production at the end of a billing period after a one-to-one netting of production and consumption has occurred. An **aggregate cap** refers to the maximum amount of capacity allowed to participate in a state or a utility's net metering program, whereas the **system size limits** are capacity limits for individual systems to net meter. **Meter aggregation** allows a single customer to offset electrical usage from multiple meters on his or her property. **REC ownership** refers to rules that specify whether renewable energy certificates/credits generated by a net-metered system accrue to the solar PV system owner or the utility. **Net metering rules** encompass other policy changes to net metering not covered by any of these other categories.

Regulatory proceedings related to net metering are currently open in several states. The New York Public Service Commission is considering modifications to its Value of Distributed Energy Resources tariff, while regulators in Arkansas and Louisiana are reviewing net metering successor tariff options. A proceeding is also ongoing in Connecticut, where regulators are working to implement successor tariff legislation enacted in 2018.

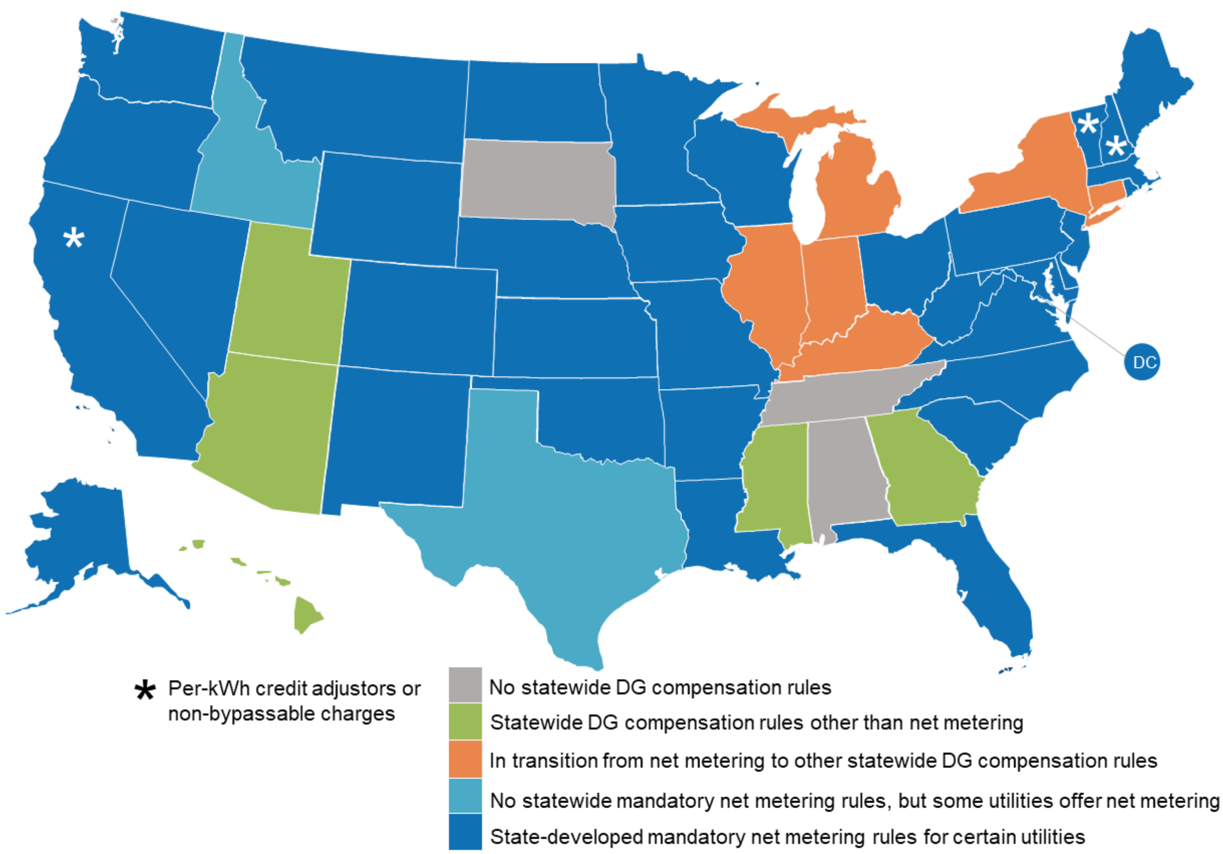
New Legislation

At least 79 bills related to DG compensation were under consideration during Q1 2019. The majority of bills address credit rates for energy exported to the grid or net metering successor tariffs more broadly. Several states also considered legislation related to DG system size. One New Hampshire bill increases the maximum system size limit for net metering from 1 MW to 5 MW, while another increases the size limit for systems classified as "small net metering systems," which receive a higher rate for net excess generation. Both New Hampshire bills have passed one legislative chamber so far.

An Arkansas bill (S.B. 145) enacted in March 2019 increases the non-residential system size limit for net metering from 300 kW to 1 MW. Kentucky's net metering bill also enacted in March 2019 adopts a more modest increase in the system size limit from 30 kW to 45 kW. A Wyoming bill that passed the House in Q1 2019 would have authorized utilities to allow net metering for systems over 25 kW, but the bill failed to pass the Senate.

Another issue addressed by several bills under consideration is the eligibility of DG systems paired with energy storage to net meter. Arkansas' S.B. 145 also authorized net metering for systems paired with storage, while an amendment that would have also done this in Kentucky was not ultimately approved. Bills in California, Illinois, New Hampshire, and South Carolina also address net metering with energy storage. A Vermont bill would have required the Public Utility Commission to develop recommendations for incorporating energy storage into the state's net metering rules, but these provisions were amended out of the bill before it passed.

Figure 4. Current Net Metering and Distributed Generation Compensation Policies



Notes: Arizona, Georgia, Hawaii, Mississippi, and Utah offer alternative compensation mechanisms for distributed generation, such as net billing. Connecticut, Illinois, Indiana, Kentucky, Michigan, and New York currently offer net metering, but are transitioning to alternative compensation mechanisms. The Idaho Public Utilities Commission has required investor-owned utilities in the state to offer net metering through separate docket proceedings; however, no statewide net metering policy exists.

Aggregate capacity limits are another topic several states are considering addressing through legislation. As utilities in states like Massachusetts, South Carolina, and Washington grow nearer to their states' aggregate caps, lawmakers are under increasing pressure to address these limits. At least four Massachusetts bills would remove or increase the state's aggregate cap, while a South Carolina would lift the aggregate cap while directing the Public Service Commission to put a successor tariff in place by May 31, 2021. A Washington bill that has currently passed the State Senate would increase the aggregate cap from 0.5% to 4% of 1996 peak demand.

Table 2. DG Compensation Legislation Under Consideration During Q1 2019

State	Bill No.	Status	Topics
Arkansas	S.B. 145	E	Credit Rates, Energy Storage, System Size
California	S.B. 288	I	Energy Storage
Connecticut	H.B. 5790	I	Study
	H.B. 6236	I	Credit Rates
	H.B. 6245	I	Credit Rates, Study
	H.B. 6629	I	Credit Rates, Study
	H.B. 6633	I	Credit Rates
	H.B. 7251	I	Credit Rates, Study
	S.B. 220	I	Credit Rates
	S.B. 429	I	Credit Rates
Illinois	H.B. 2966	I	Credit Rates, Energy Storage
	S.B. 1781	I	Credit Rates, Energy Storage
Indiana	H.B. 1421	I	Aggregate Cap, Credit Rates
	S.B. 430	I	Aggregate Cap, Credit Rates
	S.B. 499	I	Credit Rates
Iowa	H.F. 669	I	Credit Rates, Fees
	S.F. 583	P1	Credit Rates, Fees
Kansas	H.B. 2190	I	Fees
	S.B. 124	I	Fees
Kentucky	S.B. 100	E	Credit Rates, System Size
Maine	L.D. 41	I	Credit Rates, Study
	L.D. 91	E	Credit Rates
	L.D. 143	I	Credit Rates
	L.D. 790	I	Meter Aggregation
	L.D. 1139	I	System Size
	L.D. 1465	I	Aggregate Cap, Credit Rates, System Size
Massachusetts	H. 2866	I	Aggregate Cap, Net Excess Generation (NEG)
	H. 2870	I	Rules
	H. 2877	I	Aggregate Cap, NEG
	H. 2896	I	Aggregate Cap
	H. 2900	I	Fees
	S. 1956	I	NEG
	S. 1974	I	Eligible Customers
	S. 1999	I	Aggregate Cap
	S. 2006	I	Fees
Montana	H.B. 438	I	Credit Rates, Fees
Nebraska	L.B. 509	I	Fees, System Size
New Hampshire	H.B. 365	P1	System Size
	H.B. 466	P1	NEG, System Size
	S.B. 13	I	Energy Storage, System Size
	S.B. 159	P1	System Size
	S.B. 166	P1	Credit Rates, NEG
New Jersey	A.B. 2802	I	Meter Aggregation, NEG
	S.B. 2422	I	Meter Aggregation, NEG

New York	A.B. 309	I	Credit Rates
	A.B. 4090	I	Credit Rates
	A.B. 4639	I	NEG
	A.B. 5927	I	Credit Rates, System Size
	A.B. 6204	I	NEG
	S.B. 3596	I	NEG
North Dakota	S.B. 2322	D	Aggregate Cap, NEG, Study, Size
Oklahoma	S.B. 525	I	NEG, System Size
	S.B. 526	I	Rules
	S.B. 529	I	NEG
	S.B. 952	I	Credit Rates, Study
Oregon	H.B. 3325	I	System Size
Rhode Island	H.B. 5775	I	Eligible Customers
	H.B. 5789	I	Rules
	S.B. 760	I	Eligible Customers
South Carolina	H.B. 3659	P1	Aggregate Cap, Credit Rates, Energy Storage, Fees
	H.B. 3748	I	Aggregate Cap, Credit Rates
	S.B. 332	I	Credit Rates, Energy Storage, Fees
	S.B. 657	I	Aggregate Cap
Vermont	H.B. 133	A	Energy Storage
	H.B. 359	I	Credit Rates
	H.B. 520	I	System Size
Virginia	H.B. 2792	E	Meter Aggregation
	S.B. 82	D	Meter Aggregation, System Size
	S.B. 1456	D	Aggregate Cap, Fees, Meter Aggregation
	S.B. 1483	D	Meter Aggregation, NEG
	S.B. 1714	D	Meter Aggregation, NEG
	S.B. 1769	E	Aggregate Cap
	S.B. 1779	E	Meter Aggregation
Washington	H.B. 1129	I	Aggregate Cap, Credit Rates, System Size
	H.B. 1862	I	Aggregate Cap, NEG, Study
	S.B. 5118	I	Credit Rates
	S.B. 5223	P2	Aggregate Cap, Credit Rates
West Virginia	H.B. 2202	I	Credit Rates
Wyoming	H.B. 231	D	System Size

Key: I = Introduced, P1 = Passed One Chamber, P2 = Passed Both Chambers, E = Enacted, A = Relevant Provisions Amended Out, V = Vetoed, D = Dead. Legislative statuses are up to date as of mid-April 2019.

Box 4. Net Metering and Net Billing Terminology

Terminology for distributed generation compensation systems can be confusing, and with a large number of recent and proposed policy changes, the potential for confusion is pronounced right now. One point of confusion is the distinction between net metering and net billing. These terms are often used interchangeably by governments and utilities,[*] but the two approaches have important differences. After reviewing the definitions of these terms used in the academic literature,[†] we have devised definitions for net metering and net billing. These definitions should help to standardize the use of these terms and add clarity to the distributed generation policy discussion.

Net Metering is a billing mechanism that compensates a customer for excess generation from an on-site energy system through credits that offset electricity usage at other times during the billing period. Electricity generated on-site first supplies the customer's real-time use of electricity. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net metering, this excess generation is used to offset the customer's usage at other times during the billing period; credits for exported energy are deducted from the amount of electricity purchased from the utility during the billing period, in effect moving the customer's electricity meter backward. This means that customers are compensated at the retail rate for electricity exported to the grid, at least as long as total on-site generation during the billing period is less than the customer's total electricity usage during the billing period. When generation exceeds total usage during the billing period, different crediting schemes may be used.

Net Billing is a billing mechanism that compensates a customer for excess generation from an on-site energy system by payment of a separate rate for electricity generated in excess of real-time use (or excess remaining after netting production and consumption over intervals shorter than the billing period – e.g., 15-minute or 60-minute intervals.) Electricity generated on-site first supplies the customer's real-time electricity use. Any electricity generated on-site in excess of the amount used in real time is exported to the grid. Under net billing, the utility pays the customer for this excess generation at a separate rate rather than crediting the generation against usage at other times in the billing period. Under net billing, a customer's meter is essentially "stopped" when on-site generation is meeting real-time demand, but unlike with net metering, it does not go "backward". The rate of compensation for exported electricity under net billing varies by state and utility. It is usually lower than the retail rate, but is often higher than the monthly average rates paid in the wholesale electricity market. Effectively, net billing customers still receive the retail rate for on-site generation that supplies their electricity usage in real time because it displaces grid-supplied electricity they would otherwise have to purchase at the full retail rate.

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[*] For example, Mississippi calls its system "Net Metering" even though it more closely resembles net billing.
[†] Hughes, L. & Bell, J., 2006; Yamamoto, Y., 2012; Dufo-Lopez, R. & Bernal-Agustin, J., 2015.

Table 3. Updates on DG Compensation Policies (Q1 2019)

State	Type of Change	Description	Source
AR	Credit Rates, Energy Storage, Net Metering Rules, System Size	S.B. 145, as introduced, increases the non-residential net metering system size limit from 300 kW to 1 MW. The bill was significantly amended in February 2019. The amended version revises the definition of net metering so that it is technically "net billing," where the netting period is to be determined by the Public Service Commission. The amended bill directs the Commission to establish credit rates for excess generation and an appropriate netting period for customers taking service on a rate that does not include a demand component. The credit rate is to equal the avoided cost rate plus an additional sum for quantifiable benefits (which may not exceed 40% of the avoided cost rate). The Commission may also approve a per-kWh fee for these net metering customers to recover quantifiable, direct demand-related distribution costs. The bill would retain retail rate net metering for customers on a rate that includes a demand component. The amended bill still increases the non-residential system size limit from 300 kW to 1 MW. The amended bill also allows net metering facilities to include energy storage devices that are configured to receive electricity solely from the net metering facility. Furthermore, the amended bill requires municipal utilities to allow net billing. Municipal utilities may limit the system size to 25 kW for residential customers and 300 kW for non-residential customers. Municipal utilities may not establish a rate or fee that reduces the excess generation credit rate below the avoided cost rate, and the bill requires retail rate net metering to be offered to municipal utility customers on a demand rate. The Governor signed the bill into law in March 2019.	S.B. 145 (E)
	Credit Rates, Net Metering Rules	In April 2016, the Arkansas Public Service Commission (PSC) opened a docket, pursuant to Act 827 of 2015, to ensure net metering rates, terms, and conditions are appropriate to recover the full utility costs to serve net metering customers, net of any quantifiable benefits. In August 2016, the PSC approved a unanimous proposal to bifurcate and establish a separate procedural schedule for issues relating to rates, terms, and conditions for net metering ("rate issues"). The PSC also approved a proposal to establish a Net Metering Working Group to address these rate issues. In September 2017, the Working Group submitted its final joint report and recommendations. As two schools of thought exist within the working group, two	Docket No. 16-027-R Joint Report and Recommendations of the Net-Metering Working Group

		sub-groups were formed and provided separate recommendations within the report. Sub-Group 1 consists of multiple solar advocacy organizations, environmental groups, and individuals, while Sub-Group 2 consists of many utilities, the Attorney General, the PSC staff, and Arkansas Electric Energy Consumers. Sub-Group 1 recommended that the current net metering credit structure be continued until a complete study of the costs and benefits of net metering has been conducted. Sub-Group 2 recommended a move to net billing (also called "2-channel billing"), crediting excess generation at an embedded cost-of-service rate rather than the retail rate. The PSC directed parties to file briefs on nine issues in January 2018. These issues include: (1) if there is a burden of proof or persuasion in this docket, and upon which issues and party does it lie; (2) if Act 827 of 2015 requires the use of an embedded cost-of-service approach; (3) to what extent benefits outside of the embedded cost-of-service approach may be considered, and how these may be quantified; (4) if the state's statutory definition of net metering requires netting of kWhs, precluding 2-channel billing; (5) if converting kWhs to a monetary value permit or impede the use of time-of-use rates by net metering customers; (6) if the PSC is required to address any cost-shifts found to exist, or does the PSC have the discretion not to act if it finds a de minimis cost shift; (7) if there is a legal risk that FERC would consider exported kWhs a wholesale sale to the utility or that the Internal Revenue Service would consider the exported energy a wholesale sale to the utility, impacting the customer's eligibility of the federal investment tax credit; (8) if the Mississippi PSC's adder approach is consistent with Act 827; and (9) if any other states are utilizing 2-channel billing with an embedded cost of service approach. Initial briefs were filed in February 2018, and reply briefs were filed in March 2018. No action has occurred since.	
AZ	Credit Rates	In January 2019, pursuant to the Arizona Corporation Commission's final order on Tucson Electric Power's (TEP) DG export credit and rate design, TEP filed its time-of-generation (TOG) export rate option. The TOG tariff would be limited to 1,000 residential customers and provide a generation credit rate of 28 cents per kWh during on-peak hours and 7.59 cents per kWh during off-peak hours through September 2019. Rates for the following year are yet to be determined. Peak hours are 3 pm to 7 pm from May to September (weekdays) and 6 am to 9 am and 6 pm to 9 pm from October to April (weekdays). The TOG	Docket No. E-01933A-15-0322

	tariff is a buy-all, sell-all structure, providing the time-varying credit rates to all system production.	
Credit Rates	In January 2019, pursuant to the Arizona Corporation Commission's final order on UNS Electric's DG export credit and rate design, TEP filed its time-of-generation (TOG) export rate option. The TOG tariff would be limited to 300 residential customers and provide a generation credit rate of 28 cents per kWh during on-peak hours and 9.21 cents per kWh during off-peak hours through September 2019. Rates for the following year are yet to be determined. Peak hours are 3 pm to 7 pm from May to October (weekdays) and 6 am to 9 am and 6 pm to 9 pm from November to April (weekdays). The TOG tariff is a buy-all, sell-all structure, providing the time-varying credit rates to all system production.	Docket No. E-04204A-15-0142
Credit Rates, Fees	In December 2018, Salt River Project proposed new rate plans for residential DG customers. One new option is a Customer Generation Time-of-Use Export Price Plan. This plan does not include a demand charge, includes a fixed charge equal to that of the existing Customer Generation Price Plan, and features energy consumption rates equal to those of the SRP Time-of-Use Price Plan. This plan also includes a net billing compensation framework, crediting customers for energy exported to the grid at 2.81 cents per kWh. Another proposed option is the Customer Generation Average Demand Price Plan, which includes a demand charge based on the average of the daily on-peak maximum demands, rather than the maximum monthly peak demand during on-peak hours. This plan also has a fixed charge equal to that of the Customer Generation Price Plan and has energy rates equal to those of the Customer Generation Price Plan. The Board approved the new price plans in March 2019.	SRP Proposed Solar Options
Energy Storage, Net Metering Rules	In August 2018, the Arizona Corporation Commission (ACC) opened a rulemaking docket to evaluate proposed modifications to many of the state's energy rules, including net metering. Other rules to be addressed in the proceeding include the renewable energy standard, energy efficiency standards, resource planning and procurement, retail electric competition, electric vehicles, DG interconnection, blockchain technology, technological developments, forest bioenergy, baseload security, and the biennial transmission assessment. 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	Docket No. RU-00000A-18-0284

		more distributed solar and storage. A stakeholder meeting on modifications to the renewable energy standard and tariff, environmental portfolio standard, and net metering rules was held on February 25, 2019. Following the meeting the ACC Staff requested that parties provide written comments on modifications to net metering (and renewable energy standard and environmental portfolio standard) rules, the necessity of the rules, and the potential combination of the ACC's energy rules, including which sections could be integrated. Parties filed comments in late March 2019. Most comments did not address net metering, but Sunrun proposed providing customers adding storage to their DG systems with 20 years of export credit rate certainty instead of the 10 years provided to those with standalone solar. A second stakeholder workshop is scheduled for April 29, 2019.	
	Net Metering Rules	In August 2017, the Utilities Division Staff requested that the Commission open a rulemaking docket to amend net metering rules, based on changes in circumstances since their adoption. In February 2018, the Staff solicited comments from stakeholders on revisions to the existing rule, specifically on 11 questions. The questions include how export rates are addressed, which Phase II proceeding rulings to include in the revised rules, and if provisions for non-residential customers and non-solar technologies should be included. Several parties filed responses in March 2018. No action has occurred since.	Docket No. RE-00000A-17-0260
CA	Credit Rates, Net Metering Rules	In late June 2018, the Riverside County Board of Supervisors introduced an ordinance establishing net metering rules for irrigation districts. The ordinance requires Imperial Irrigation District to offer a net metering program that is at least as expansive as and no more restrictive than the California Public Utilities Commission's net metering rules applicable to Southern California Edison. The ordinance was approved unanimously in July 2018. Imperial Irrigation District has sued Riverside County, suggesting that the ordinance conflicts with state law. In November 2018, a judge issued a preliminary injunction, which blocks implementation of the ordinance until the case is resolved.	Ordinance No. 943 Summary Court Filing Preliminary Injunction
	Credit Rates, Net Metering Rules	Bear Valley Electric Service filed an application in March 2019 to implement a new Distributed Generation Service (DGS) program, which functions as net billing. The utility met its 5% net metering aggregate cap in October 2016, but continued accepting new customers until January 1, 2018. Bear Valley Electric Service is not bound by the Commission's rules on the net metering successor	Docket No. A19-03-011

	tariff, so the DGS program is intended to serve as its successor to net metering. The credit rate for excess generation includes four compensation elements: (1) avoided energy costs, (2) renewable attribute rider, (3) avoided transmission access charges, and (4) avoided line losses. The application also provides that these values can be recalculated annually by April 30th. The initial values in the application, not including the renewable attribute rider, total $0.03152 per kWh. The utility requested a final decision by September 2019.	
Energy Storage, Net Metering Rules, System Size	A January 2016 decision from the California Public Utilities Commission (CPUC) established a successor tariff to replace net metering. Since the successor tariff was adopted, the CPUC has continued to use this docket to explore other issues related to customer generation, several of which have already been decided. A Fourth Scoping Ruling, filed in March 2018, identified and established the schedule for the remainder of the issues in the docket. Two of the remaining issues are related to net metering-eligible facilities paired with energy storage. A proposed decision issued in August 2018 addressed a petition for modification of a previous decision to modify the definition of "small" net metering paired with energy storage from "less than or equal to 10 kW" to "less than or equal to 30 kW." A decision issued in October 2018 denied this petition. As it stands, systems 10 kW or smaller paired with storage can participate in net metering without needing to install additional metering equipment to measure the actual storage or renewable output. Larger systems paired with storage can net meter, but need to install certain metering equipment. A proposed decision issued in late December 2018 sets these equipment requirements 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.	Docket No. R14-07-002 Decision No. 18-10-005 (Denial of modification of small NEM paired with storage) Decision - Consumer Protection and Solar Information Packet Proposed Decision – Non-bypassable Charges

		A ruling issued in March 2019 solicited comments on enhanced consumer protection measures for net metering customers, as well as briefs on parties' positions regarding the authority of the CPUC over third-party solar providers. Comments were due in March 2019, and briefs are due in April 2019. A proposed decision issued in March 2019 addressed an application for rehearing of the original 2016 order adopting the successor tariff. Specifically, the application and the proposed decision address the assessment of non-bypassable charges for customers under the successor tariff. The order rules that non-bypassable charges should be assessed only on the kWh consumed in each metered interval net of exports.	
CO	Credit Rates, Energy Storage, Net Metering Rules, System Size	In February 2019, the Colorado Public Utilities Commission opened a rulemaking docket with proposed changes to electric resource planning, the 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 proposed net metering rules specify how net metering under a TOU rate is handled (excess energy generated during a particular time period is compensated at the rate for that time period). The rules also authorize utilities to install a second meter to measure the output of the system, at the system owner's expense. The rules prohibit customers from being required to change rate schedules in order to install renewable DG. The rules also specify that the customer's retail rates are the rates to be used for net metering credits and that utilities may not prohibit customers from participating in TOU rates. Utilities are permitted to bill net metering customers a surcharge to supplement the customer's contribution to the Renewable Energy Standard Adjustment account. The proposed rules specify that an energy storage system may be paired with the renewable DG system. Parties filed their initial comments in March 2019. Xcel Energy's comments generally supported the proposed rules, but took issue with the specification of rates for net metering. Solar industry parties expressed concern about some of the rules regarding TOU rates for net metering and requested clarification of the 120% rule on self-generation sizing limits.	Docket No. 19R-0096E
CT	Credit Rates, Net Metering Rules	In May 2018, Connecticut's Governor signed S.B. 9 into law. The bill increases the state's renewable portfolio standard, while making significant changes to net metering. The bill closes net metering to new customer-generators when the state's residential solar investment program ends or when regulators	Docket No. 18-06-15 S.B. 9 (2018)

	establish the new compensation program - whichever occurs first. Existing net metering customers will be grandfathered until December 31, 2039. The Public Utilities Regulatory Authority (PURA) is to establish a per-kWh rate for electric distribution companies to purchase electricity generated by these customers after December 31, 2039. Upon closure of the existing net metering program, new DG customers will be able to select a buy-all, sell-all option or a net billing option. The PURA is tasked with determining the netting period for the net billing option, which must either be: real time, one day, or a fraction of a day. The PURA opened a proceeding in June 2018 to review the requirements of the new legislation and develop a strategy and procedural roadmap for implementation. Technical meetings were held in July and August 2018. The July meeting addressed the DG tariff rate, including incorporation of system benefits and the netting period. By September 2019, PURA will initiate a proceeding to develop the new DG compensation tariffs, the compensation rate, and the netting period. By July 2019, the Department is to submit these requirements and tariffs to the Public Utilities Regulatory Authority (PURA) for approval.	
Credit Rates, Net Metering Rules	This proceeding was opened in late August 2018 to establish procurement plans and tariffs pursuant to Act 18-50 (S.B. 9), enacted in May 2018. The Public Utilities Regulatory Authority (PURA) accepted comments on several questions related to a net metering successor tariff during October 2018, including whether an interim residential tariff should be established before the expiration of the esidential solar investment program. A technical meeting was held in mid-October 2018 to discuss the Department of Energy and Environmental Protection's (DEEP) solar PV tariff calculator and the net metering successor comments filed. In late October 2018, Eversource and the United Illuminating Company filed their proposed procurement plan for non-residential zero-emission and low-emission projects up to 2 MW. The two proposed compensation structures include a buy-all, credit-all option and a real-time net metering option. Shared clean energy facilities and a residential tariff are not addressed in the plan. A technical meeting was held in early December 2018 to discuss the utilities' proposed procurement plan. In mid-December, several parties, including the DEEP, utilities, Office of Consumer Counsel (OCC), and Green Bank, filed a Joint Interim Rate Proposal for establishing an interim residential tariff. The goal of the interim tariff is to ensure a smooth transition after the end of the residential solar investment program and to provide the utilities with a timeline for implementing changes to their billing and metering	Docket No. 18-08-33

		systems. The group did not reach consensus on the specific details of the tariff, but the proposal provides two options: a buy-all, sell-all tariff and a netting tariffs (two structures - instantaneous with a high $/kWh rate or monthly netting with a cap for $/kWh compensation). In early January 2019, the DEEP and OCC recommended that PURA begin its investigation into final residential solar tariffs (net metering successor). The DEEP and OCC recommended using DEEP's model to calculate final tariff rates, soliciting and validating data inputs for the model, using a real-time or at most a sub-daily netting interval, and investigating tax treatment, third-party payments, and battery storage back-up. Several solar parties filed comments opposing these recommendations. The PURA issued a request for comments in January 2019 on (1) tariff implementation details that need to be resolved for the utilities to begin updating their metering and billing systems for the successor tariff and (2) the Green Bank's proposal to extend the residential solar investment program deadline (anticipated to be October 2019) to allow more time for tariff development. A hearing was held in early April 2019.	
DC	Net Metering Rules, System Size	The Public Service Commission is examining interconnection issues in Formal Case No. 1050. A September 2018 order established a Net Energy Metering Working Group to address system upgrade costs related to the interconnection of community renewable energy facilities (CREFs), review the Commission's current net metering rules, and propose CREF-specific rules changes for the Commission's consideration. Another decision, issued later in September tasked the Net Energy Metering Working Group with considering whether the system capacity limit should be increased beyond 100% of a customer's historical usage. The working group held meetings in December 2018, February 2019, and April 2019.	Formal Case No. 1050 Order No. 19676 Order No. 19692
FL	Credit Rates, Net Metering Rules	In April 2018, Solar United Neighbors and the League of Women Voters of Florida filed a complaint for declaratory judgment and injunctive relief regarding the legality of JEA's revised DG compensation program. The petitioners contend that the new rules do not comply with the state's net metering law and are requesting an injunction requiring the utility to offer a net metering program that meets state statutory requirements. In February 2019, the plaintiffs filed a motion for summary judgment that JEA's policy violates Florida Statutes 366.91.	Complaint Motion for Summary Judgment
IA	Credit Rates, Fees, Net	H.F. 669 and S.F. 583 make significant changes to Iowa's net metering policy. The bills establish four	H.F. 669 (I)

	Metering Rules	options for new DG customers to take the place of the current net metering policy: (1) net metering with a minimum bill, (2) net metering with a demand charge, (3) buy-all, sell-all with an avoided cost credit rate, and (4) an undetermined cost of service based rate structure that may be proposed by the utility. Current net metering customers would be grandfathered in for the lifetime of their equipment. S.F. 583 passed the Senate in March 2019, while the House bill has not advanced.	S.F. 583 (P1)
ID	Net Excess Generation	In March 2019, Pacificorp filed a petition to amend its net metering tariff in order to allow customer-generators to transfer net excess generation credits between eligible meters once per year. Eligible meters must be owned by the same customer and located on or contiguous to the premises where the net metering system is located. The meters must also be served by the same primary feeder and be on the same rate schedule. In late March 2019, the Commission Staff recommended setting a comment deadline of June 12, 2019.	Docket No. PAC-E-19-03
KY	Credit Rates, Energy Storage, Net Metering Rules, System Size	S.B. 100 increases the maximum system size eligible for net metering from 30 kW to 45 kW. The bill also requires the Public Service Commission to determine new monetary credit rates for energy exported to the grid that recover all costs of serving net metering customers, without regard to the rate structure for non-net metering customers. Customers taking service under current net metering rules would be grandfathered for 25 years. An amendment to the bill allows energy storage systems to be paired with net metering facilities and also allows leased systems to net meter. The amendment also allows customer-generators to take service under current net metering rules until 2024, even after the successor tariff is developed; these customers would be eligible for the current net metering tariff until 2034. The amendment was ultimately withdrawn and the bill passed in March 2019. The Governor signed the bill into law late in March.	S.B. 100 (E)
LA	Aggregate Cap, Credit Rates, Fees, Net Excess Generation, Net Metering Rules, Virtual Net Metering	In December 2015, the Louisiana Public Service Commission (PSC) initiated a two-phase rulemaking proceeding to (1) modify the state's current net metering rule once a utility reaches the state's existing net metering aggregate cap, and (2) examine appropriate changes to solar policies in Louisiana. In December 2016, the PSC adopted the staff's recommendation filed in April 2016, reducing the credit rate for net excess generation from retail to avoided cost.	Docket No. R-33929 Final Proposed DG Rules (Part 1) Final Proposed DG Rules (Part 2)

Parties filed initial Phase II comments in February 2017. Entergy Louisiana, SWEPCO, Cleco, and the Association of Louisiana Electric Cooperatives all proposed moving from retail rate net metering to “net billing" or “2-channel billing,” where all excess generation is credited at the avoided cost rate. Entergy and SWEPCO acknowledged that time-varying rates are another option to examine, although they state the utilities would potentially propose an increased fixed charge or a demand charge to accompany them and there are additional metering costs involved. SWEPCO also proposed reducing the residential system size limit from 25 kW to 10 kW to prevent oversized systems and is supportive of establishing a new aggregate cap. Cleco suggested the Commission could set system size limits based on an average usage study. The Alliance for Affordable Energy proposed maintaining retail rate net metering and considering an increase to the aggregate cap, as well as time-varying or location-based credit rates. The Alliance also suggested consideration of community solar or aggregation options. The Sierra Club also supports maintaining retail rate net metering, but re-evaluating the basis for the current aggregate cap and clarifying that existing customers are grandfathered under current rules. The Sierra Club proposed consideration of a moderate minimum bill to ensure fixed cost recovery. Solar leasing and efficiency services company Posigen proposed that an independent consultant specializing in clean energy deployment and IT infrastructure be hired to analyze demand-side management resources, including residential solar, before any changes be made to net metering.

In November 2017, the Commission Staff published proposed modified net metering rules. The new rules take the form of net billing, rather than net metering, crediting customers at the avoided cost rate for excess generation. The rules provide for two possible methods of avoided cost calculation: (1) the method established by the PSC's February 1998 order, or (2) innovative avoided cost rates including allowances for environmental and avoided peak capacity benefits. Existing DG customers, as of January 1, 2018, would be grandfathered under the former net metering policy for five years (until December 31, 2022). If a customer significantly modifies their system, it would no longer be grandfathered. The proposed rules establish a system size limit of 100% of the customer's expected annual electricity consumption and broaden eligibility from renewable only to all types of DG facilities.

The rules also allow additional fees or customer charges to be assessed on DG customers, following

		notice and opportunity for comment, as well as evidence supporting the fee request. The proposed rules also allow for community DG facilities up to 300 kW and require DG to be incorporated into integrated resource planning. Customers may carry over net excess generation, and will be monetarily compensated annually for any remaining excess. The proposed rules state that DG customers will not be charged for meter replacement, only if the DG customer requests an additional meter themselves. Comments were filed in January 2018, and an open session was held in February 2018. The Commission Staff filed final proposed modified rules in January 2019, with include most of the same provisions as the previous version of the Staff's proposed rules.	
MA	Energy Storage, Net Metering Rules	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 eligibility of net metering facilities to participate in the Forward Capacity Market (FCM). 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. 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 issued an additional order in February 2019 determining that the capacity rights of Class II and III net metering facilities transfer to 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, and a new proceeding was opened to revise model net metering and SMART tariffs.	Docket No. 17-146 Energy Storage Order Capacity Rights Order Docket No. 19-24
MD	Credit Rates	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid modernization proceeding to make sure that the electric distribution system in	Public Conference 44 Order (DP&L)

		Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding is addressing rate design, costs and benefits of DERs, advanced metering infrastructure, valuing energy storage, streamlining the interconnection process, evaluating distribution system planning, and protecting limited income customers. In August 2017, the rate design working group submitted a report detailing its two proposed TOU rate pilots, both of which net metering customers would not be eligible to participate in. In November 2017, the PSC published an order stating that the materials submitted during the workgroup and report are not sufficiently specific to approve the pilot programs. The PSC directed the workgroup leaders to continue convening the group to refine the design of the two pilot programs – one for customers who wish to receive standard offer service, and another for customers wishing to receive service from a retail supplier. The workgroup submitted a report in response to this order in February 2018. The report includes a consensus approach for net metering customer participation in the pilot programs. The approach tracks on-peak and off-peak consumption and production separately, and nets each separately. Any excess in either category will be carried forward to the next month, while any net consumption in either category will be due at that time. At the end of the annual period, any remaining net excess generation in either category will be compensated at the non-TOU supply-only rate currently paid to net metering customers. In June 2018, the PSC approved the workgroup's proposed timeline for the development of the TOU pilots, which includes a deadline of April 1, 2019 for the new tariffs to be rolled out. The utilities filed their marketing and outreach plans in July 2018, and parties provided comments. The workgroup filed an interim report in November 2018, identifying areas where consensus was and was not reached. The utilities filed a revised implementation, marketing, and outreach plan in November as well. In December 2018, the PSC directed the utilities to proceed with implementing the TOU pilots as proposed in the utilities' November filing. A pair of March 2019 orders approved the utilities' revised TOU tariffs.	Order (Pepco)
ME	Credit Rates, Net Metering Rules	In September 2018, the Conservation Law Foundation filed a lawsuit against the Public Utilities Commission, challenging the legality of the new buy-all, sell-all DG compensation rules adopted in 2017 and implemented in early 2018. The Foundation and other petitioners (Industrial Energy Consumer Group,	Complaint

		ReVision Energy, and Natural Resources Council of Maine) are seeking a declaration that the new rules are arbitrary, capricious, and an abuse of discretion. The suit was previously filed with the Maine Supreme Judicial Court, which dismissed the challenge, finding that it should go to a lower court. The September 2018 petition was filed with a Maine Superior Court. L.D. 91, enacted in early April 2019, restores the state's previous DG compensation rules.	
	Credit Rates, Net Metering Rules	L.D. 91, introduced in January 2019, clarifies the definition of net energy billing to refer to a practice that bills customers based on the difference between energy delivered by the utility to the customer and energy delivered by the customer to the utility over the billing period. This new definition would not allow the current gross metering practice (used in the state's buy-all, sell-all successor to net metering) to comply with the net energy billing statute, therefore restoring net metering in the state. The Governor signed the bill into law in early April 2019.	L.D. 91 (E)
MI	Credit Rates, Fees, Net Metering Rules	In July 2018, as part of a general rate case, DTE Electric proposed a rate structure for new DG customers based on Michigan's new "inflow/outflow" methodology for DG compensation (see Docket No. 18383). All inflows will be charged at full retail rate, while outflows from a customer's DG system will be credited at the monthly average real-time locational marginal price (LMP) at the relevant DTE node. Outflow credits will not be allowed to offset non-energy customer charges. Unused outflow credits will be carried over to the next month indefinitely. New DG customers will also pay a system access charge of $2.31 per kW of DG system capacity. The ALJ filed a proposal for decision in March 2019. The proposal for decision would keep the inflow charge at the retail rate and set the outflow credit rate at the power supply rate, excluding transmission costs. The proposal for decision also rejects DTE's proposed system access charge.	Docket No. U-20162 Docket No. 18383 Proposal for Decision
	Credit Rates, Fees, Net Metering Rules	In September 2018, as part of its general rate case, UPPCO proposed a rate structure for new DG customers based on Michigan's new "inflow/outflow" methodology for DG compensation (see Docket No. 18383). All inflows will be charged at the full retail rate, while outflows will be credited according to the power supply charge for the relevant rate class. Outflow credits will not be allowed to offset non-energy customer charges. Unused outflow credits would be carried over to the next month indefinitely. New DG customers will also pay a system access charge based on DG system capacity, although the amount of this charge was not specified in the initial	Docket No. U-20276 Docket No. 18383

		filings. In February 2019, the Commission Staff recommended deleting the system access charge language, as a value was never specified, and also recommended that outflow credits be allowed to offset all parts of the bill, not just power supply charges. A final order is expected by August 21, 2019.	
	Net Metering Rules	On November 8, 2018, the Michigan Public Service Commission opened this docket to conduct an investigation of interconnection rules, legally enforceable obligations under PURPA, DG (including energy storage), and legacy net metering rules. A stakeholder meeting was held in December 2018, and all working groups held meetings in January and March 2019.	Docket No. U-20344
	Net Metering Rules	In January 2019, Consumers Energy requested a waiver of the company's obligation to comply with certain requirements of Michigan's Electric Interconnection and Net Metering Standards. The provisions the utility requested to have waived include the 10-day completeness determination and application review periods, as well as the deadlines for engineering review and distribution system studies. Several parties filed objections to the application in February 2019. In February 2019, the Great Lakes Renewable Energy Association (GLREA) filed a letter requesting that a stakeholder comment process be opened.	Docket No. U-20444
MO	Net Metering Rules	In September 2017, the Missouri Public Service Commission (PSC) opened a docket to review the Commission's rules on cogeneration and net metering. The docket is intended to gather information and conduct a workshop. Stakeholders submitted comments on the effectiveness of the current rules and suggested changes to the rules through mid-November 2017. Utility comments generally recommended against changing current net metering rules, while noting potential cost-shift issues, and argued against undertaking a new value of solar study. Renew Missouri agreed that current net metering rules are not in need of revision and argued that any cost shift issues should be addressed only after a value of solar study is undertaken. In May 2018, the PSC published a draft rule change pertaining to net metering. The rule changes would make it so that net metering rates for systems larger than 100 kW would not have to be the same as the utility's cogeneration rates. The amended rules would also require utilities to maintain an information database for resource planning containing information on net-metered systems, and require that the process for calculation of net energy be specified in net	Docket No. EW-2018-0078 Proposed Net Metering Amendment

		metering tariffs. The proposed changes would delete existing language specifying the manner for determining net electrical energy, defining net metering, and stating that customer-generators own RECs unless receiving solar rebates. The draft also deletes language including the aggregate cap and prohibiting additional fees from being imposed on only customer-generators. These deleted sections are, however, included in the state's net metering statute (386.890 RSMo), and would, therefore, not impact current net metering requirements. A workshop was held in February 2019 to discuss changes to interconnection rules to reflect 2018 updates to the IEEE interconnection standards.	
MT	Customer Class, Fees, Net Metering Rules	In NorthWestern Energy's general rate case, filed in late September 2018, the utility proposed the separation of future residential net metering customers into a new customer class. The proposal retains monthly netting of production and consumption, but includes an $8.64/kW demand charge for future residential net metering customers.	Docket No. D2018.2.12
NH	Credit Rates, Net Metering Rules	S.B. 166 requires competitive electricity suppliers to purchase net generation from net metering customers under the same rules and tariffs as Commission-regulated utilities. The Senate passed an amended version of the bill in March 2019. The amended version changes the bill language to require competitive electricity suppliers to credit net generation output from net metering customers at the same retail rate at which the customer is purchasing energy from the competitive supplier.	S.B. 166 (P1)
	Net Excess Generation, System Size	H.B. 466 increases the system size limit for small net metering facilities from 100 kW to 500 kW. Small net metering facilities receive a higher rate for net excess generation than large net metering facilities. The House passed the bill in March 2019.	H.B. 466 (P1)
	Net Metering Rules, System Size	H.B. 365 and S.B. 159 increase the eligible system size limit for net metering from 1 MW to less than 5 MW. The bills also grandfather these larger systems under current net metering rules until December 31, 2040. The House and Senate passed amended versions of these bills in March 2019. The amended versions also include language allowing systems less than 5 MW that became operational before July 1, 2019 and have outstanding ISO-New England capacity commitments to participate in net metering and be treated as retail load reducers if they retire from participation in ISO-New England wholesale markets.	H.B. 365 (P1) S.B. 159 (P1)

NY	Credit Rates, Fees, Net Metering Rules	In March 2017, the New York Public Service Commission (PSC) issued a net metering transition order, addressing Phase I of the Value of Distributed Energy Resources (VDER) proceeding and outlining a procedure for Phase II of the proceeding. In May 2017, the PSC created working groups and protocols for Phase II of the VDER proceeding. Three working groups are looking at: (1) the value stack, (2) rate design, and (3) low and moderate income issues. The working groups will support the PSC Staff to develop recommendations. The PSC published a schedule with working group meetings going from January 2018 to December 2018, culminating in a white paper from the PSC staff. In April 2018, the utilities published a Rate Design Handbook to define and explain the uniform approach they developed for parties to submit rate design proposals. During Q2 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 TOU rate proposal submitted by the clean energy parties, a TOU rate proposal from PSC Staff, a demand rate proposal from the joint utilities, and a combined demand and TOU rate proposal from the joint utilities. In July 2018, the Department of Public Service Staff published a white paper on VDER compensation for avoided distribution costs. In the paper, Staff proposed replacing the de-averaged demand reduction value with system-wide marginal cost estimates used for energy efficiency benefit-cost calculations. The tariff would be updated every two years, as opposed to annually. Staff recommended two options for customers: (1) provide a $/kWh rate for the 460 peak summer hours used for the tariff's Capacity Value Option 2 or (2) establish a call signal to provide a $/kW-year value over 10 peak load hours (this option would be aimed at dispatchable resources, like storage). The Staff filed final versions of the white papers in December 2018. In December 2018, the PSC issued an order accepting the hybrid tariff for Distributed energy systems that include battery storage (hybrid facilities). The tariff includes four options: Options A and B offer an environmental credit value, the market transition credit, and capacity credit value for all grid exports by ensuring that only renewable energy is injected to the grid. Option C uses multiple meters to determine whether injections are from renewable energy or not, and Option D uses monthly netting. The rate design	Matter No. 17-01276 (Value Stack) Matter No. 17-01277 (Rate Design) NYSERDA VDER Resources

		working group met in mid-April 2019 and will meet again on May 23, 2019.	
OH	Net Excess Generation, System Size	The Public Utilities Commission of Ohio approved amendments to the state's net metering rules in November 2017. The new rules set the maximum system size limit at 120% of a customer's average annual usage. Customers receiving standard service from a regulated utility will be compensated monthly for net excess generation at the utility's standard service offer rate for energy. Competitive retail electric suppliers may offer net metering to their customers and compensate excess generation at any price, rate, credit, or refund amount agreed to between the supplier and the customer. Various parties filed applications for rehearing, which the Commission granted in January 2018. An additional hearing was held in January 2018. The Commission issued a Fifth Entry on Rehearing in December 2018, officially amending the net metering rules. Ohio Power Company and Dayton Power & Light both filed applications for rehearing in January 2019, and various parties filed memoranda opposing the companies' applications for rehearing. The Commission granted the applications for rehearing in February 2019, but a Seventh Entry on Rehearing, filed later in the month, denied the applications for rehearing.	Docket No. 12-2050-EL-ORD PUCO Order
PR	Credit Rates, Net Excess Generation	Puerto Rico's S.B. 1121 requires the Puerto Rico Electric Power Authority and any other utilities to use net metering to compensate DG customers. The bill also sets the compensation rate for net excess generation at 75% of the retail rate. The legislature passed the bill in March 2019, and the Governor signed the bill into law in April.	S.B. 1121 (E)
SC	Aggregate Cap	In July 2018, Duke Energy Carolinas announced that it reached its aggregate capacity limit for net metering in South Carolina. The utility stated that it would be closing net metering to new participants beginning August 1, 2018, and that new customer-generators would be able to sell energy produced by their systems through the Purchase Power Tariff (buy-all, sell-all program, crediting gross production at the avoided cost rate). In September 2018, the utility filed a joint petition with other parties to extend net metering until March 15, 2019. The Commission approved the petition, and Duke filed its revised tariff later in the month. In March 2019, Sunstore Solar Energy Solutions filed a request for an expedited review and amendment of the Commission's order approving the net metering extension so that Duke Energy Carolinas would be able to accept net	Docket No. 2015-55-E

	metering applications for a waitlist pending resolution of active legislation addressing this issue (H.B. 3659).	
Aggregate Cap, Credit Rates, Energy Storage, Fees, Net Excess Generation, Net Metering Rules	H.B. 3659, as introduced, establishes a customer's right to reduce energy purchased from the utility through energy cost-saving measures, including installation of DERs. The bill prohibits utilities from adopting additional fees that only apply to customers using energy cost-saving measures, requiring these customers to take service on a separate rate schedule, or increasing interconnection fees apart from an initial cost-based application fee. The bill also prohibits 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 bill also adds energy storage systems that are configured to charge only from an on-site renewable energy resource to the definition of customer-generator. The bill calls for a successor net metering tariff to take the place of the current net metering tariff once aggregate net-metered capacity equals at least 2% of the previous five-year average of the utility's retail peak demand. If the cap is reached before a successor tariff is approved, new customers will still be allowed to begin net metering on the existing tariff. The successor tariff is to credit any monthly net excess generation at the approved DER rate. The bill was amended before it passed the House in February 2019. The amended bill establishes a customer's right to reduce energy purchased from the utility through energy cost-saving measures, including installation of DERs. The bill requires utilities to make net metering available to all customer-generators who apply before June 1, 2021, and grandfathers these customers through May 31, 2029. The bill also requires the Public Service Commission to adopt a successor tariff (the "solar choice metering tariff") to take effect on May 31, 2021. The solar choice metering tariff is to include compensation for customer-generators for the benefits they provide to the system. The tariff is to eliminate cost shifts and allow customer-generators to use generated energy behind the meter without penalty. By January 1, 2020, the Commission is to open a generic docket to investigate the costs and benefits of net metering and develop a methodology for calculating the value of energy produced by customer-generators.	H.B. 3659 (P1)

UT	Credit Rates, Net Metering Rules	In September 2017, the Public Service Commission (PSC) approved a settlement agreement between Rocky Mountain Power and solar advocates on the future of net metering in the state. The settlement agreement closed net metering to new DG customers on November 15, 2017. Customers beginning to net meter by this date are grandfathered under the current rules through December 31, 2035. If ownership of the property changes during this period, the system remains grandfathered. An Export Credit Proceeding will be conducted to determine the credit rate for energy exported to the grid by new DG systems, while on-site consumption will be permitted. The PSC established a transition program for new customer-generators to participate in after the close of retail rate net metering and before the new export credit rate is decided. The transition program takes the form of net billing, rather than net metering, with an export credit rate of 9.2 cents/kWh for residential customers, netted in 15-minute intervals. The settlement established an aggregate cap for the transition program of 170 MW for residential and small non-residential customers. As part of the agreement, the parties agreed not to advocate for any changes to rates, charges, and fees for grandfathered net metering or transition customers that do not apply to the entire customer class. Customers submitting a complete interconnection application after this cap is reached will receive the transition credit rate until the new export rate is determined through the Export Credit Proceeding. The Commission opened a new docket for the Export Credit Proceeding in December 2017. A load research study workshop was held in January 2018, and RMP filed its proposed load research study plan in February 2018. A hearing was held in April 2018, and the Commission issued an order on Phase I of the proceeding in May. The study period will run for 12 months, beginning no later than January 1, 2019. Parties disagreed on the type and scope of data to be collected through the study. Based on parties' criticisms and recommendations, the Commission directed RMP to increase its sample size to accommodate the separate study of residential and commercial customers and to select new samples from both classes that give each member of the class an equal chance of being selected, rather than mixing an existing sample drawn from a subset of the class with a new sample from the entire class. The Commission also directed RMP to collect production, export, and import data from existing net metering customers. Vote Solar, Utah Clean Energy, and Vivint Solar filed a petition for rehearing in June on certain	Docket No. 17-035-61 (Export Credit Rate Proceeding) Docket No. 14-035-114 Docket No. 16-035-T14

		sample design and data collection issues. The Commission addressed the petition and issued an order on review in July 2018. The order clarifies the Commission's Phase I order, but does not modify it. Rocky Mountain Power gave an update on Phase II of the proceeding in early October 2018. In late November 2018, several solar advocates filed a joint motion to amend the procedural schedule to hold at least two additional technical conferences in the first half of 2019. The parties also requested that the Commission agree to accept no-cost technical assistance from relevant experts at multiple national laboratories. In late January 2019, the PSC issued an order denying the request to amend the procedural schedule, but granting the request for technical assistance. Rocky Mountain Power submitted a filing suggesting that the technical assistance should be limited to a few topics, noting that the current topic list is too expansive and not sufficiently focused enough to be of much value.	
	Net Excess Generation	In October 2018, the Public Service Commission opened an investigation into expiring excess generation credits from Rocky Mountain Power's Schedule 135 (net metering tariff that closed to new applicants in November 2017). Currently, the value of expiring excess generation credits is applied to the Home Electric Lifeline Program (HELP), but several parties recommended applying these credits to an alternative program. Parties filed comments in November 2018. In January 2019, the Commission issued an order directing Rocky Mountain Power to provide a one-time disbursement of the current excess credit balance to each customer qualifying for HELP.	Docket No. 18-035-39
VA	Aggregate Cap, Fees, System Size	S.B. 1769 makes certain changes to the net metering rules for electric cooperatives. It increases the aggregate capacity limit from 1% to 7%, and increases the system size limit from 100% of the customer's demand to 125%. The bill also allows a cooperative utility to implement demand charges for its net metering customers. The Governor signed the bill in March 2019.	S.B. 1769 (E)
	Meter Aggregation	H.B. 2792 and S.B. 1779 establish a new pilot program for net metering by municipalities. The pilot program allows a single renewable energy system of 2 MW or less to offset the metered usage at multiple municipally-owned buildings. The Governor signed the bill in March 2019.	H.B. 2792 (E) S.B. 1779 (E)
VT	Net Metering Rules	In December 2017, the Vermont Department of Public Service, Natural Resources Board, and Agency of Natural Resources requested that the Public Utility	Docket No. 17-5202-PET

		Commission hold a workshop related to the definition of the term "preferred site" in the state's net metering rules. A prehearing conference was held in March 2018, and workshops were held in June and July 2018. The Commission will issue guidance regarding the definitions of preferred sites, and draft rule changes will be published for comment at a date to be determined. The proceeding remains open.	
WA	Aggregate Cap, Credit Rates, Customer Class, Meter Aggregation, Net Excess Generation, Net Metering Rules	S.B. 5223, as introduced, increases the state's aggregate cap on net metering from 0.5% of the utility's 1996 peak demand to 4%. The bill also specifies that any unused net metering credits at the end of the annual billing period are to be used to assist qualified low-income residential customers. Additionally, the bill directs the Department of Commerce to convene a work group to identify issues and laws associated with the future of net metering. The Department is to submit a report with the work group's recommendations by December 1, 2020. The recommendations are to include the circumstances that would warrant a change in compensation for net metering systems and what the policy should be for customer-generators in the same rate class. The group is also to consider if there are cost shifts associated with net metering and provide an inventory of other state's net metering laws. The bill was amended multiple times before passing both legislative chambers. The final bill requires utilities to offer net metering until the aggregate capacity of net metering systems equals 4% of the utility's 1996 peak demand or June 30, 2029, whichever comes sooner. After June 30, 2029 or once the aggregate cap is reached, a consumer-owned utility may establish a net metering successor tariff and utilities regulated by the Commission may submit a successor tariff proposal for approval. The Commission would be required to approve, reject, or approve with conditions the tariff within one year of its filing. The bill also addresses meter aggregation.	S.B. 5223 (P2)
WI	Net Excess Generation	In late December 2018, Northwestern Wisconsin Electric Company filed a petition to adjust its compensation rate for net excess generation to net metering customers from retail rate to avoided cost. This petition references a similar adjustment made to North Central Power Company's rates made in Docket No. 4190-ER-107. The application was approved in early April 2019.	Docket No. 4280-TE-101
WV	Fees, Net Metering Rules	The Public Service Commission opened a new docket in September 2018 to consider revisions to net metering and interconnection. To begin the proceeding, the Commission provided a draft of	GO 258.3 Proposed Rules

		revisions to the existing net metering rules based on the recommendations of the Net Metering Task Force. The draft revisions include a provision that the charges for energy consumption in the net metering tariff should be the same as those in the standard service tariff. The rules also require that fixed charges and other charges not related to energy consumption should not exceed comparable charges in the standard service tariff by more than the costs directly incurred by the utility to accommodate the net metering system. The rules maintain retail rate net metering, but include a provision that net metering credits may not reduce the bill below the fixed monthly minimum bill plus any charge for the Incremental Cost of Connection, which is defined in the proposed rules. The rules also change the financial responsibility for a bi-directional meter from the utility to the customer. The Commission received comments on the proposed rule changes from a number of parties. A March 2019 order reopened the comment period and scheduled a public hearing for April 30, 2019. Parties filed testimony in early April 2019.	
WY	Net Metering Rules	The Wyoming State Legislature's Joint Committee on Corporations, Elections, and Political Subdivisions identified net metering as a priority topic for study during the interim period.	Corporations, Elections, & Political Subdivisions Committee
	System Size	H.B. 231 allows utilities to authorize the use of net metering systems over 25 kW. The bill passed the House in February 2019, but was not considered in the Senate.	H.B. 231 (D)

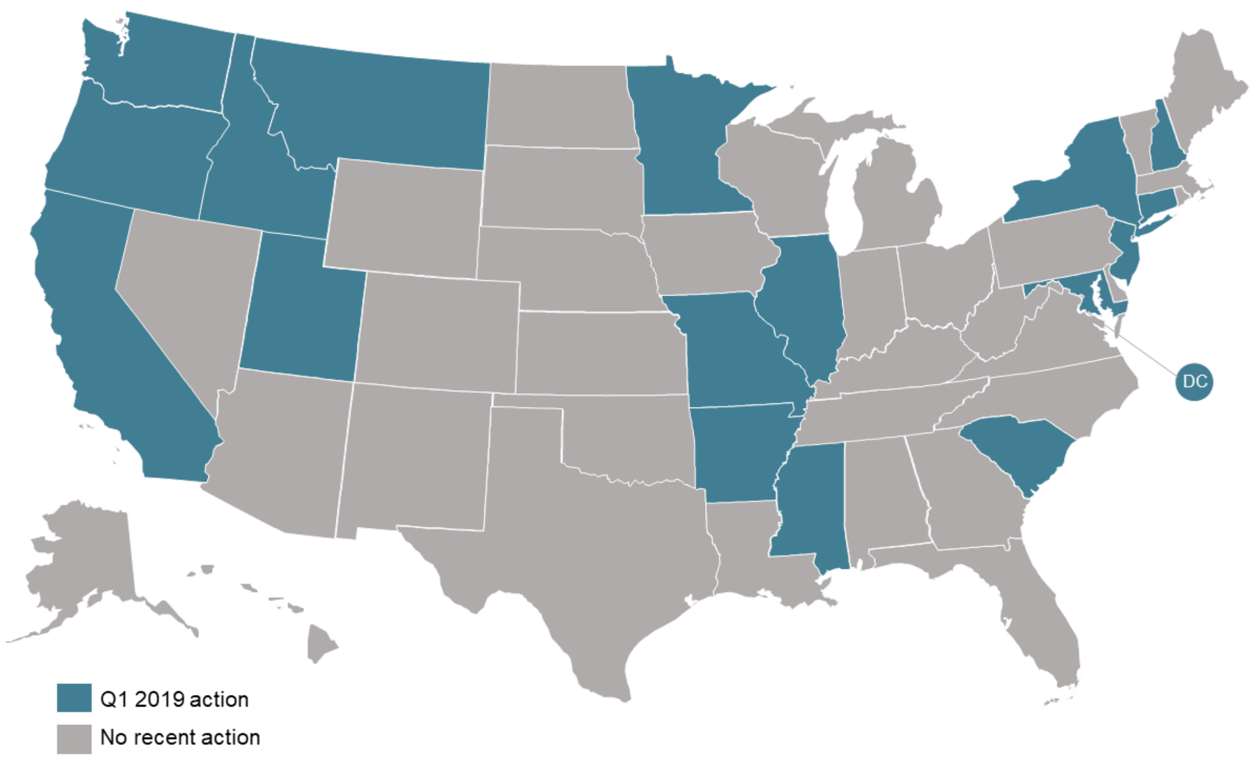
DISTRIBUTED SOLAR VALUATION STUDIES

Key Takeaways:

- In Q1 2019, 17 states and DC were in the process of examining some element of the value of distributed generation.
- A consultant filed a final report on the benefits of distributed generation in Mississippi, finding avoided cost rates of 2.659 cents/kWh and 3.488 cents/kWh.
- Oregon utilities filed their updated Resource Value of Solar calculations, which range from 4.273 cents/kWh to 6.244 cents/kWh.

In Q1 2019, 17 states and DC were engaged in the process of examining the value of distributed generation. A distributed generation (DG) valuation study was completed in one state – Mississippi – during Q1 2019, while a bill addressing DG valuation advanced in South Carolina.

Figure 5. Action on Distributed Solar Valuation and Net Metering Studies (Q1 2019)



The Mississippi Public Service Commission's hired consultant, Acadian Consulting filed a final report calculating the total avoided cost rates for solar in the service territories of Entergy Mississippi and Mississippi Power in March 2019. The avoided cost rates are based on avoided generation capacity, avoided transmission and distribution capacity, and avoided costs related to line losses and ancillary service costs. An "effective load carrying capability" of

28.7% was applied to all the values to account for a solar resource's availability during the hours the system is peaking, resulting in total values of 3.488 cents per kWh for Entergy Mississippi and 2.659 cents per kWh for Mississippi Power.

The Oregon Public Utility Commission adopted final methodologies for the state's investor-owned utilities to use in calculating each of their initial Resource Value of Solar, which includes 11 components. The utilities filed their updated values in March 2019. Pacificorp calculated a real value of 5.086 cents per kWh and a nominal value of 6.244 cents per kWh. Idaho Power calculated 4.273 cents per kWh for standard size projects and 4.716 cents per kWh for utility-scale projects. Portland General Electric calculated 4.988 cents per kWh for December 2017 and 5.016 cents per kWh for March 2019.

Other states continued making progress towards DG valuation studies during the quarter. The New Hampshire Public Utilities Commission approved the Staff's proposed locational value of DG study scope and encouraged the Commission Staff to work with the consultant to develop a flexible and accessible valuation model for net metering technologies other than solar. The South Carolina State House passed a bill in February 2019 directing the Public Service Commission to open a generic docket to investigate and determine the costs and benefits of net metering and also establish a methodology for determining the value of the energy produced by customer-generators.

Table 4. Updates on Distributed Solar Valuation and Net Metering Studies (Q1 2019)

State	Description	Source
AR	In April 2016, the Public Service Commission (PSC) opened a general proceeding regarding DERs. In November 2017, the PSC issued an order outlining specific topics and questions to address during this proceeding, including many related to advanced metering infrastructure (AMI) deployment, pursuant to the final order in Entergy Arkansas' AMI deployment proceeding. These issues include identification of the benefits and costs of DERs (including rate and bill impacts) for customers that participate measures and programs, as well as non-participants. Benefits to individual customers should be distinguished from system benefits. The PSC issued an order in July 2018 with an initial list of issues to be considered during the proceeding. These issues include the appropriate roles for distribution utilities, third-party DER providers, and customers; tariff-based DER programs; net metering and rate design; and DER compensation and program design for low-income participation among many other specific DER and grid modernization issues. Comments on the proposed issues were accepted until late September 2018, and the Commission intends to schedule an initial educational workshop on procedural issues.	Docket No. 16-028-U Order No. 10
CA	California has an ongoing proceeding to consider the development of a consistent regulatory framework for the planning and evaluation of DERs. The proceeding is addressing two activities: (1) the establishment of a Competitive Solicitation Framework, which involves creating cost-effectiveness methods for evaluating bids and (2) the adoption of a Utility Regulatory Incentive Pilot for the procurement of DERs that displace or defer the need for capital expenditures on traditional distribution infrastructure. The Commission's Energy Division revised its proposal on the Societal Cost Test, which could help build upon the cost-effectiveness methods for evaluating bids from the Competitive Solicitation. In June 2018, the Commission issued a decision modifying a prior decision related to the funding of the Utility Regulatory Incentive Pilot. As part of the Pilot, the utilities were required to procure one or more DER projects and evaluate the effectiveness of the solicitation process and the performance of the DERs. The modified decision addressed the possibility of a pilot project involving distribution equipment funded through a general rate case. The decision states that in such a case, the funding for the pilot project should come from the general rate case funds and not be funded separately. In September 2018, the ALJ requested comments on whether it is reasonable for the Commission to approve a utility-administered contract for future cost-effectiveness modeling work. In November 2018, San Diego Gas and Electric (SDG&E) filed an evaluation report for 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.	Docket No. R14-10-003 Decision No. 18-06-010 ALJ Ruling

	A ruling issued in January 2019 directed parties to respond to a series of questions regarding the development of an annual 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 beginning on July 1, 2019 for all DERs 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) 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.	
CT	In December 2017, the Public Utilities Regulatory Authority (PURA) opened a docket for its investigation into distribution system planning. Among the specific topics to be addressed is rate design alternatives. In March 2018, the PURA sought comments focusing on the integration of DERs, grid modernization, implementing an appropriate rate design to optimize system benefits, and other topics. Technical meetings were held in April, July, and October 2018. Phase II of the proceeding will include assessing the costs, benefits, and implications of specific solutions and implementing these in appropriate proceedings. A public hearing was held in late October, with briefs accepted in November and reply briefs in December 2018. A final decision had not yet been issued as of early April 2019.	Docket No. 17-12-03
DC	DC has an ongoing proceeding primarily related to grid modernization, which led to a Modernizing the Distribution Energy Delivery System for Increased Sustainability (MEDSIS) report in early 2017. In February 2018, the Public Service Commission 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 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 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. The working groups met several times and filed a joint draft report with their recommendations in April 2019. Among the recommendations detailed by the Rate Design working group was a recommendation for a value of DER and value of grid study. Given the inherent complexity of a locational value of DER and value of the grid study, the working group recommended the Commission	Formal Case No. 1130 Draft Working Group Recommendations

	hire an outside consultant to produce a methodology for determining the value of DER before 2021.	
ID	In October 2018, Idaho Power filed a petition to open a docket to study the cost and benefits of on-site generation. This follows an order in Docket No. IPC-E-17-13 approving Idaho Power's request to separate DG customers into a separate customer class and evaluate credit rates for excess generation. Rates, rate design, transitional rates, and net excess generation compensation will be considered in this proceeding. In December 2018, the Commission Staff proposed an initial schedule, with a broad list of issues being provided to the Staff in early January 2019, followed by two settlement meetings in January. The Staff provided an update in late February, noting that the parties are working collaboratively toward establishing a study scope and methodologies. The Commission issued an order in March 2019 allowing parties to continue working toward a settlement and directing the Staff to provide another progress update by May 28, 2019.	Docket No. IPC-E-18-15
	In October 2018, Idaho Power filed a petition to open a docket to study the fixed costs of providing electric service to customers. This information will be considered in future rate design changes for DG customers, per Docket No. IPC-E-17-13. A prehearing conference was held in January 2019.	Docket No. IPC-E-18-16
IL	In March 2017, the Illinois Commerce Commission opened a proceeding to investigate grid modernization and the creation of a 21st century regulatory model. The NextGrid proceeding is being conducted as a facilitated stakeholder process. Topics include, but are not limited to (1) consumers, communities, and economic development; (2) grid design, digital networks and markets; (3) regulation and encouraging innovation; and (4) climate change and the environment. A conference and launch event for the proceeding took place in late September 2017, and working groups were formed on seven topics: (1) new technology deployment and grid integration, (2) electricity markets, (3) customer and community participation, (4) regulatory, environmental, and policy issues, (5) metering, communications, and data, (6) reliability, resiliency, and cyber security, and (7) ratemaking. Draft reports from all seven working groups were published on the NextGrid website in September 2018. The draft reports for Working Groups 1, 6, and 7 contain discussion of DERs, with Working Group 1 focusing on DER integration and valuation. Working Group 6 focuses on the environmental benefits of DERs, and Working Group 7 summarizes the aspects of DER valuation that need to be considered in ratemaking. Working groups 1 and 7 discuss the need to recognize how DER value can differ depending on location and grid factors. The draft reports do not make specific policy proposals. A draft final report compiling the working group reports was published in December 2018; public comments were filed in early January 2019. The release of the final NextGrid report has been delayed due to a lawsuit regarding procedural issues.	Docket No. 17-0142 NextGrid Website Draft Final Report (Dec. 2018) Working Group 1 Draft Report Working Group 6 Draft Report Working Group 7 Draft Report
MD	In September 2016, the Maryland Public Service Commission (PSC), as part of the Exelon-PHI merger condition, initiated a grid	Public Conference 44

	modernization proceeding to ensure that the electric distribution system in Maryland is customer-centric, affordable, reliable, and environmentally sustainable. The proceeding is considering topics including rate design, costs and benefits of DERs, maximizing advanced metering infrastructure, valuing energy storage, streamlining the interconnection process, evaluating distribution system planning, and protecting limited income customers. A consultant was hired to study the benefits and costs of distributed solar in Exelon-PHI territory, including solar's health and environmental benefits, an examination of geographic and grid location, and how advancing energy storage technology and cost-effectiveness can enhance distributed solar's benefits. Following the release of a draft report in April 2018, Daymark Energy Advisors published the final report in November 2018 on the benefits and costs of utility-scale and behind-the-meter solar resources in Maryland. The report, funded by the PSC, provides an analysis of the costs and benefits of solar within each of the four electric utilities in the state. The values of behind-the meter solar vary by utility and decrease over time from a current value of approximately 30 - 38 cents per kWh to approximately 25 - 30 cents per kWh in 2028. The values for utility-scale solar also vary by utility and increase over time from a current value of approximately 15 - 19 cents per kWh to approximately 19 - 21 cents in 2028. Parties filed comments on the final report in December 2018. A hearing will be held on April 23, 2019 to discuss the report.	Draft: Benefits and Costs of Utility Scale and Behind The Meter Solar Resources in Maryland Final: Benefits and Costs of Utility Scale and Behind The Meter Solar Resources in Maryland
MN	Minnesota has an ongoing proceeding related to community solar gardens. A September 2016 decision transitioned the credit rates for subscribers from the retail rate to the value of solar rate. The Commission also called on the Department of Commerce to comment on whether the credit rate should be adjusted with a positive or negative adder for seven categories, some location-specific and others customer-specific. The Department of Commerce filed its recommendations in March 2017, suggesting that only residential subscribers receive an adder to make community solar more attractive. The Commission issued an order related to the proposal in December 2017, declining to approve or deny the Department's proposal. Instead, the Commission asked Xcel Energy for an analysis of the potential rate impact of the Department's proposal, and how a solar carve-out for community solar projects would be implemented and enforced. Xcel Energy provided its analysis in February 2018. The Commission then issued an order in November 2018, approving a $0.015/kWh adder to the value of solar rate for residential subscribers. The adder will be available for a two-year term as a pilot, and available to projects with a 2019 or 2020 value of solar vintage year. Also in this proceeding, Xcel filed its 2019 Value of Solar rate in August 2018. The proposed rate is a decrease from the rate used in previous years and would negate the adders applied by the Commission's November order. In December 2018, Xcel filed for approval of its proposed Community Solar Garden (CSG) tariffs. In February 2019, the Commission issued an order denying petitions for reconsideration of the November 2018 order. The Commission issued a second order in February to clarify that its approval of a	Docket No. 13-867 Order

	decrease in the value of solar rate was inherent within its November order. The Commission issued an order in March 2019 approving Xcel's 2019 Value of Solar Rate as modified in the order to account for a revised consumer price index value and an alternative methodology for calculating capacity factor.	
MO	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, including the Public Utility Regulatory Policies Act (PURPA), Missouri statutory provisions, net metering and cogeneration rules, avoided cost calculations, value of solar calculations, development and construction of utility-scale or community solar projects, and other states' activities. Information regarding the PSC's role in implementing modified rate design proposals, such as residential TOU rates, is also requested. The proceeding is also intended to examine issues surrounding advanced metering infrastructure, property assessed clean energy financing, and the electric vehicle market. The PSC Staff released its 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, the PSC Staff filed 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 published an updated version for comment. The current version of the draft rule requires utilities to maintain a database on 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.	Docket No. EW-2017-0245 July 2017 Staff Report April 2018 Staff Report May 2018 Draft Rule June 2018 Draft Rule
MS	Earlier in 2018, the Mississippi Public Service Commission issued an RFP for a consultant to conduct a study of the benefits of DG, as required by the state's net metering rule. In July 2018, the Sierra Club, Gulf States Renewable Energy Industries Association, and 25 x '25 Alliance filed a motion to amend the timeframe for the study and consolidate it with the 5-year review docket, due to the state's limited solar development. Acadian Consulting was hired to conduct the study, and a public meeting was held in early August for interested parties and stakeholders to provide information relevant to the study. Acadian Consulting published a draft report in November 2018, which the Commission is accepting comments on for 45 days from the date of its order. The Commission extended the deadline for comments until February 2, 2019. Entergy and the American Solar Energy Society (ASES) filed comments on the report, with Entergy largely supporting the report and ASES finding major issues and recommending that the report be rejected by the Commission. Acadian Consulting submitted its final report in March	Docket No. 2011-AD-2 Final Report: Actual Benefits of Distributed Generation in Mississippi

	2019, finding a total avoided cost rate of 3.488 cents per kWh for Entergy Mississippi and 2.659 cents per kWh for Mississippi Power. This rate includes only avoided generation capacity, avoided transmission and distribution capacity, and avoided costs related to the net cost of new entry, southeast generation costs, implied capacity premium, and MISO RPA - Zone 10. The report recommends adopting a 0.35 cent per kWh adder for net billing credit rates for Entergy Mississippi and a 0.27 cent per kWh adder for Mississippi Power.	
MT	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 initiative goals and alternatives. A meeting was held on November 30th to discuss a decoupling proposal and force-field analysis. Another 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
NH	Pursuant to H.B. 1116 of 2016, the Public Utilities Commission (PUC) issued a final order approving a net metering successor tariff in June 2017. In the decision, the PUC ordered a value of DER study to be conducted by a qualified consultant under the Commission's guidance in order to inform "Phase 2" changes to the state's DG compensation policy. The study is to be a long-term avoided cost study using marginal cost concepts and incorporating both the Total Resource Cost and Ratepayer Impact Measure test criteria, as well as consideration of demonstrable and quantifiable net benefits associated with relevant externalities. The study period is to be 10 to 15 years - a compromise between the 3 to 5 years proposed by the coalition of utility and consumer parties and 25 years proposed by the coalition of solar and sustainable energy interests. The study will focus on solar PV and hydroelectric facilities. A stakeholder working group met throughout the rest of 2017 and beginning of 2018, and filed its proposed DER study scope in May 2018. The proposed study scope includes an hourly avoided cost calculation, as well as a distribution-level valuation study conducted either as a separate study or as part of the DER study to evaluate locational value. The study period will be 15 years, with 3 to 5 years of historic data reviewed. The study will not include a high DG penetration scenario. The avoided cost components to be evaluated in the study include energy, capacity market costs, ancillary services and load obligation charges, renewable portfolio standard (RPS) compliance, transmission charges, transmission capacity, distribution capacity, distribution system operating expenses, transmission and distribution line losses, wholesale market price	Docket No. DE 16-576 Order No. 26,029 DER Study Scope Locational Value of Distributed Generation Study Scope Proposal Order No. 26,221

	suppression, hedging/wholesale risk premium, distribution utility administration costs and expenses, transmission and distribution system upgrades required, utility lost revenues, externality benefits, distribution grid support services, resilience services, and customer installed net costs. Consensus among stakeholders was achieved on methodologies for energy, capacity market costs, ancillary services and load obligation charges, RPS compliance, transmission charges, distribution capacity, line losses, wholesale market price suppression, administrative costs, transmission and distribution system upgrade costs, distribution grid support services, and resilience services. The group did not reach consensus on the inclusion of and/or methodologies for transmission capacity, distribution system operating expenses, hedging, utility lost revenues, externality benefits, and customer installed net costs. The study will be conducted by an independent consultant and is expected to be completed in 2020. A public comment hearing on the proposed study scope was held in late June 2018, with written comments submitted in July. In mid-July 2018, Eversource filed a marginal cost of service study to be used in the valuation study. 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 proposed study period is limited to 10 years. The study is expected to begin in Q2 2019 and be completed by the end of 2019. In February 2019, the Commission approved the proposed 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. Eversource is to file an updated marginal cost of service study. In March 2019, the PUC granted the Office of the Consumer Advocate'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.	
NJ	In May 2018, New Jersey Governor Murphy signed the Clean Energy Act into law, which directed the Board of Public Utilities (BPU) to complete a study on the SREC program transition and successor to encourage efficient and orderly development of solar in the state. In December 2018, the BPU released a staff straw proposal on the New Jersey Solar Transition. The proposal includes several questions about the New Jersey solar market that the staff is seeking comments on from stakeholders. Among these questions is if the SREC program cost cap should be based on net costs and include a valuation of associated benefits and if the transition to the SREC successor program should also encompass changes to the net metering program. A stakeholder meeting was held in January 2019. Comments from stakeholders were accepted until February 22, 2019. A proposed rule is expected to be presented to BPU in September 2019, with timeline to adopt the rule by March 2020.	Staff Straw Proposal on the New Jersey Solar Transition

NY	In March 2017, the Public Service Commission issued an order on the future of net metering in the New York. The order is one of the major milestones in New York's Reforming the Energy Vision proceeding, addressing the transitional steps from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff that aims to accurately value and compensate DERs. Community solar, remote net-metered projects, and large distributed energy projects began to be compensated through the Phase I Value Stack tariff in March 2017. The VDER tariff includes energy (based on LMP), capacity, environmental, and demand reduction credits. Mass market DER projects are able to continue with the Phase I net metering tariff, which is identical to the previous net metering tariff, except that it includes a 20-year contract term. All projects interconnected prior to March 9, 2017 are able to continue with traditional net metering. In September 2017, the PSC issued an order finalizing Phase I VDER implementation. Phase II of the VDER proceeding, initiated in June 2017, is working to refine and improve the value stack, address rate design issues, and support participation for low to moderate income ratepayers. The PSC formed two parallel working groups addressing the value stack and rate design. In December 2018, the Department of Public Service Staff filed white papers on (1) VDER Capacity Value Compensation and (2) VDER Compensation for Avoided Distributed Costs. The goal of the VDER Phase II proceeding is to establish a new method of compensation for distributed generators based on the actual, calculable value these systems provide. The two white papers present the Staff's proposed methods to calculate capacity value and avoided distributed costs. Staff recommended two options for customers regarding capacity value: (1) provide a $/kWh rate for the 460 peak summer hours used for the tariff's Capacity Value Option 2 or (2) establish a call signal to provide a $/kW-year value over 10 peak load hours (this option would be aimed at dispatchable resources, like storage). In the distribution costs paper, the Staff recommended sunsetting the locational system relief value.	Docket No. 15-02703/15-E-0751 Matter No: 17-01276 (Value Stack) Matter No: 17-01277 (Rate Design) VDER Resources
OR	The Public Utility Commission (PUC) is investigating the resource value of solar (RVOS). The RVOS will be used to compensate systems enrolled in the Solar Volumetric Incentive Program after their 15-year payment schedule has expired. However, the RVOS could be utilized in other ways in the future as well. The PUC held several workshops and hearings throughout 2015, 2016, and 2017 to identify elements to include in the valuation and the methodology for calculating them. In September 2017, the PUC issued Order No. 17-357, formally closing Phase I of the proceeding and adopting the RVOS. The RVOS utilizes eleven elements (energy, generation capacity, transmission and distribution capacity, line losses, administration, market price response, RPS compliance, integration and ancillary services, hedge value, environmental compliance, and security, reliability, and reserves) for calculating an hourly avoided cost load profile for each year of the life of a solar PV system. The order outlines the methodology for valuing nine out of the eleven	Docket No. UM 1716 Order No. 17-357 Docket No. UM 1912 (Portland General Electric) Docket No. UM 1910 (Pacific Power) Docket No. UM 1911 (Idaho Power)

	elements, resolving to value RPS compliance and grid services at a later date. To initiate Phase II of the proceeding, the PUC directed the utilities to make their RVOS filings in utility-specific dockets. The utility calculations resulted in the following RVOS values: Pacificorp - $49.72 to $52.00 per MWh, Idaho Power - $45.01 per MWh (utility-scale), and Portland General Electric - $49.88 per MWh. These calculations do not include values for RPS compliance or grid services. Orders filed in each of the utility-specific dockets in January 2019 adopted the final methodologies for each utility to calculate its initial set of RVOS values. This first set of values will include both a real levelized and nominal levelized price expression based on a generic resource. The second round of updated values, however, will begin to evolve the RVOS to reveal the true system value of individual resources rather than the levelized estimated life-time value of a generic resource configuration. In the short term, the order makes determinations on the methodology for each utility to use in calculating each of the 11 RVOS components. The Commission adopted the utilities' proposed approach in some cases, the staff's recommendations in others, and modifications of proposed approaches in other cases. The utilities filed their updated RVOS Value in March 2019. Pacificorp's includes a real value of $50.86 per MWh and a nominal value of $62.44 per MWh. Idaho Power calculated $42.73 per MWh for standard size projects and $47.16 per MWh for utility-scale projects. Portland General Electric calculated $49.88 per MWh for December 2017 and $50.16 per MWh for March 2019.	
SC	H.B. 3659, as amended, requires the Public Service Commission to open a generic docket to investigate and determine the costs and benefits of the current net energy metering program and establish a methodology for calculating the value of the energy produced by customer-generators. In evaluating the costs and benefits of the net energy metering program, the Commission must consider the aggregate impact of customer-generators on the utility's long-run marginal costs of generation, distribution, and transmission; the cost of service implications of customer-generators on other customers within the same class, including an evaluation of whether customer-generators provide an adequate rate of return to the utility compared to the otherwise applicable rate class; the value of distributed energy resource generation according to the methodology approved by the commission in Commission Order No. 2015-194; the direct and indirect economic impact of the net energy metering program to the state; and any other information the commission deems relevant. The value of the energy produced by customer-generators must be updated annually and the methodology revisited every five years. The House passed the bill in February 2019.	H.B. 3659 (P1)
UT	In November 2016, Rocky Mountain Power (RMP) proposed a new tariff for net metering customers. In a settlement agreement approved in September 2017, parties agreed that a separate proceeding will be initiated to determine a new export compensation rate for DG systems. Participating parties will be able to present	Docket No. 14-035-114 Docket No. 17-035-61

	"evidence addressing reasonably quantifiable costs or benefits or other considerations they deem relevant." The Public Service Commission (PSC) will determine the study period length for quantifying and modeling credit rate components. A new docket for the Export Credit Proceeding was opened in December 2017. A load research study workshop was held in January 2018, and RMP filed its proposed load research study plan in February 2018. The Commission issued an order on Phase I of the proceeding in May 2018. The study period will run for 12 months, beginning no later than January 1, 2019. Parties disagreed on the type and scope of data to be collected through the study. Based on parties' criticisms and recommendations, the Commission directed RMP to increase its sample size to accommodate the separate study of residential and commercial customers and to select new samples from both classes that give each member of the class an equal chance of being selected, rather than mixing an existing sample drawn from a subset of the class with a new sample from the entire class. The Commission also directed RMP to collect production, export, and import data from existing net metering customers. Vote Solar, Utah Clean Energy, and Vivint Solar filed a petition for rehearing in June on certain sample design and data collection issues. The Commission addressed the petition and issued an order on review in July 2018. The order clarifies the Commission's Phase I order, but does not modify it. Rocky Mountain Power gave an update on Phase II of the proceeding in early October 2018. In late November 2018, several solar advocates filed a joint motion to amend the procedural schedule to hold at least two additional technical conferences in the first half of 2019. The parties also requested that the Commission agree to accept no-cost technical assistance from relevant experts at multiple national laboratories. In late January 2019, the PSC issued an order denying the request to amend the procedural schedule, but granting the request for technical assistance. Rocky Mountain Power submitted a filing suggesting that the technical assistance should be limited to a few topics, noting that the current topic list is too expansive and not sufficiently focused enough to be of much value.	Order Approving Settlement Stipulation RMP Proposed Load Study Plan Order on Review
WA	In April 2018, the Utilities and Transportation Commission Staff filed draft distribution system planning rules. The proposed rules require utilities to file forecasts of customer-owned DERs on the utility system and to identify potential tariffs and rate designs that compensate customers for the value of their DERs and provide accurate price signals for acquiring and using these resources. The Commission has held a series of stakeholder meetings and accepted comments on the proposed rules.	Docket No. U-161024 Distribution Planning Draft Rules
	H.B. 1126 provides additional requirements for utilities engaging in DER planning processes. The bill specifically references cooperative efforts by utilities to quantify the locational and temporal value of resources on the distribution system. The House passed the bill in March 2019.	H.B. 1126 (P1)

S.B. 5223 directs the Department of Commerce to convene a work group to identify issues and laws associated with the future of net metering. The Department is to submit a report with the work group's recommendations by December 1, 2020. The recommendations are to include the circumstances that would warrant a change in compensation for net metering systems and what the policy should be for customer-generators in the same rate class. The group is also to consider if there are cost shifts associated with net metering and provide an inventory of other state's net metering laws. The bill was amended in March 2019, removing the study provisions.	S.B. 5223 (Relevant Provisions Amended Out)

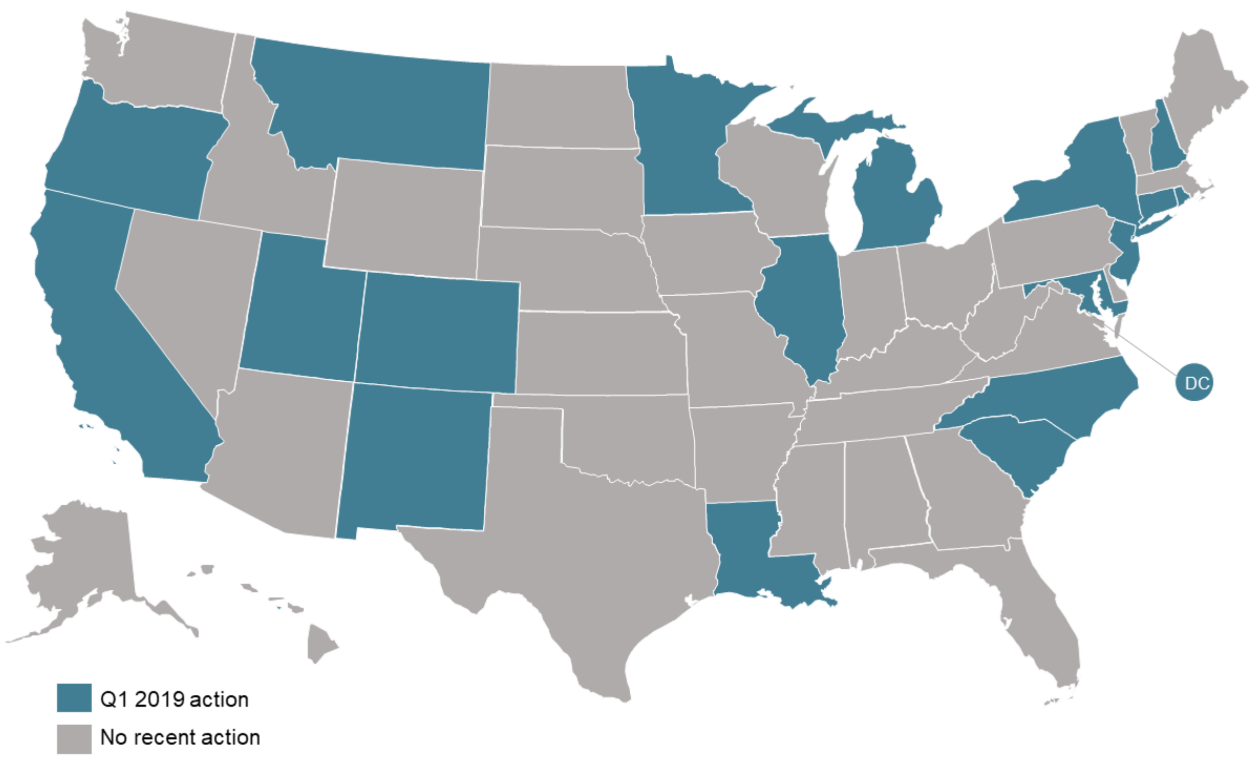
COMMUNITY SOLAR POLICY

Key Takeaways:

- In Q1 2019, 18 states plus DC considered changes to state community solar policies or community solar programs arising from state policies.
- The Utah State Legislature enacted a bill authorizing Rocky Mountain power to file an application for community renewable energy programs.
- Several states, including Florida, Nevada, New Mexico, Pennsylvania, and South Carolina, considered adopting community solar enabling policies.

Community solar programs offer the potential to expand solar access to more individuals and businesses by allowing utility customers to benefit from a system located away from their premises. Community solar is currently authorized at the state level in fewer than half of U.S. states, and the rules vary greatly from state to state. However, policymakers are showing growing interest in community solar, with a number of states enacting legislation to enable community solar projects.

Figure 6. Action on Community Solar Policy (Q1 2019)



Utah became the 20th state to adopt a community solar policy with the enactment of H.B. 411 in March 2019. The bill authorizes Rocky Mountain Power to file an application for a community renewable energy program and establishes certain parameters for such a program. Utah's policy is much narrower than most states' community solar policies. It includes the highly specific requirement that participating customers must be located in a municipality or county that adopts by December 31, 2019 a resolution pledging to achieve 100% renewable energy by 2030.

The New Jersey Board of Public Utilities approved the state's community solar pilot program rules in January 2019. The final rules include retail rate bill credits for participants, a 40% capacity carve-out for low to moderate income customers, a maximum program cap of 75 MW for the first year of the program, and a minimum required capacity amount of 75 MW each for years two and three. The Colorado Public Utilities Commission opened a rulemaking in February 2019, including proposed community solar changes that would allow participants to contribute excess credits to a nonprofit established for low-income energy assistance.

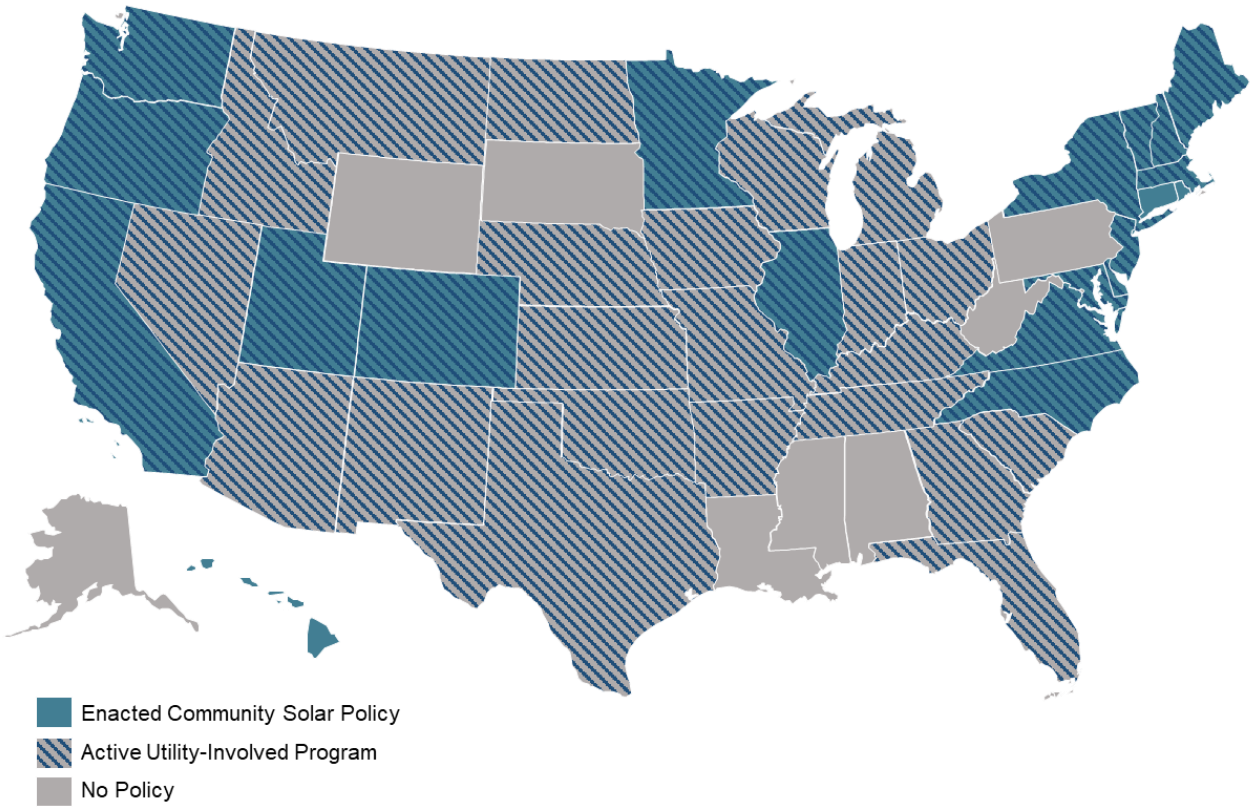
Box 5. What is Community Solar?

Community solar refers to a voluntary program for customers where a solar PV system "provides power and/or financial benefits to, or is owned by, multiple community members."[5] While some community solar projects share similarities with utility-scale solar projects (e.g., large in size, located off-site from consumption, ground-mounted systems, utility-side of the meter), this report, which focuses on distributed solar, includes policy actions related to these programs because they are community-focused and provide residential customers a way to invest in solar energy. Community solar programs included in this report may be administered by a utility or third party, but are enabled or mandated under state rules encouraging the development of such programs. Community solar is also sometimes referred to as "shared solar," or "solar gardens." Some of the state policies that enable these programs include "virtual" or "remote" net metering, in which net metering is expanded to apply to customers who have invested in an offsite PV system.

Community solar legislation was under consideration in at least 19 states during Q1 2019. Several states that do not currently have a community solar policy in place, such as Florida, Nevada, New Mexico, Pennsylvania, and South Carolina, are considering legislation adopting such policies. Community solar enabling bills in New Mexico and South Carolina have passed the states' respective Houses. Notably, all of the states listed above include provisions, such as carve-outs, to encourage low-income participation in the bills to establish new community solar policies.

At least 16 bills related to community solar are currently pending in the Minnesota Legislature. Several of the bills relate to consumer protections for community solar participants, and a pair of bills would increase the system size limit for community solar projects. Another pair of companion bills would repeal the state's community solar gardens law. Other bills remove a current requirement for subscribers to be located in the same county or a contiguous county as the project or relate to project procurement.

Figure 7. State Community Solar Policies & Utility Community Solar Programs



Source: NC Clean Energy Technology Center; Smart Electric Power Alliance[6]

Table 5. Examples of Low-Income Community Solar Provisions

State	Low-Income Provisions
California	The CPUC directed Pacific Gas & Electric and Southern California Edison to solicit Community Solar Green Tariff projects to serve disadvantaged communities in the San Joaquin Valley.
Connecticut	Connecticut's program reserves 10% of total program capacity and 10% of each community solar project's capacity for low to moderate income customers or low-income service organizations.
Illinois	The Illinois Solar for All program includes an additional 6 to 13 cents per kWh for low-income community solar projects.
Maryland	Maryland's pilot program includes a 60 MW carve-out for projects focused on low to moderate income customers.
Massachusetts	The SMART program includes an adder of 6 cents per kWh for community solar projects serving low to moderate income customers.
Minnesota	Xcel Energy's Rehabilitation and Efficiency: Neighborhood Energy Works (RENEWs) pilot program combines community solar subscriptions with energy efficiency improvements for certain low-income customers.
New Jersey	New Jersey's community solar pilot program rules include a 40% carve-out for low to moderate income customers.

Table 6. Updates on Community Solar Policies (Q1 2019)

State	Description	Source
CA	A.B. 2672 of 2014 required the California Public Utilities Commission (CPUC) to initiate a proceeding to identify disadvantaged communities in the San Joaquin Valley and analyze the economic feasibility of alternative energy options that would increase access to affordable energy. Phase I of the proceeding identified disadvantaged communities. Phase II will address the authorization and implementation of pilot projects intended to provide cleaner and more affordable energy for some of the disadvantaged communities identified in Phase I. The CPUC is considering community solar as a possible pilot project. In a December 2017 Scoping Ruling, the CPUC directed parties to answer a series of questions related to a potential community solar pilot project. Parties filed their responses to the questions during Q1 2018, and Southern California Edison stated its interest in developing community solar pilot projects. The CPUC hosted a status conference and an all-party workshop in April 2018 to discuss the pilot proposals submitted by the utilities. A ruling issued in June 2018 required the parties to develop a joint proposal addressing economic feasibility standards for the proposed pilot projects, and to present the proposal at a workshop in late July. Following that workshop, an August ruling requested comments on eight questions drawn from workshop discussions related to the pilot projects. A proposed decision filed in November 2018 authorizes the proposed pilot projects, which include an expansion of the Community Solar Green Tariff program, which was authorized under Docket No. R-14-07-002 (see above). A final decision issued December 13, 2018, approved the pilot projects. The Public Advocates Office filed an application for rehearing in January 2019.	Docket No. R15-03-010 Final Decision
	In late September 2018, Southern California Edison filed an application for approval of five new Green Energy Programs, which will replace the existing Green Tariff Shared Renewables Program in 2021. In its application, Southern California Edison cited several challenges associated with the Green Tariff Shared Renewables Program, which has hampered its adoption by customers. The proposed programs aim to avoid these challenges. One of the proposed programs is a New Community Renewables Program. One or more large business or government customers in the community must sponsor the facility and commit to purchase a minimum of 80 percent of the facility's output, with the remainder made available to residential and small business customers in the community. Numerous parties filed protests to the application. A prehearing conference took place in December 2018. In January 2019, the Commission issued a ruling denying a motion to dismiss from Shell and directing parties to file briefs on the issues.	Docket No. A-18-09-015
CO	In February 2019, the Colorado Public Utilities Commission opened a rulemaking docket with proposed changes to electric resource planning, the renewable energy standard, net metering, community solar, PURPA, and interconnection rules. The proposed community solar rules would allow subscribers to contribute any excess monthly billing credits to a nonprofit established for low-income energy assistance, pursuant to C.R.S. Section 40-8.5-104. Parties filed their initial comments in late March 2019. Xcel Energy's comments generally supported the proposed rules but took issue with the specification of	Docket No. 19R-0096E

	rates for net metering. Solar industry parties expressed concern about some of the rules regarding TOU rates for net metering and requested clarification of the 120% rule on self-generation sizing limits.	
	In February 2019, several solar companies filed a petition with the Colorado Public Utilities Commission seeking to delay or amend agreements that they entered into with Xcel Energy to construct community solar gardens to reflect possible changes to the state's community solar laws being considered in H.B. 1003. On March 15, 2019, the Commission rejected the petition.	Docket No. 19V-0104E
	H.B. 1003, the Community Solar Gardens Modernization Act, increases the maximum size of a community solar garden project from 2 MW to 10 MW and removes the requirement that a subscriber must be located in the same county or an adjacent county to the community solar garden they are subscribing to. This bill passed the House in March 2019.	H.B. 1003 (P1)
CT	In May 2018, Connecticut's Governor signed S.B. 9 into law. The bill increases the state's renewable portfolio standard, while making significant changes to net metering and shared clean energy programs. The bill directs the Department of Energy and Environmental Protection (DEEP) to initiate a proceeding by September 2018 to develop program requirements and tariff proposals for shared clean energy facilities. By July 2019, the Department is to submit these requirements and tariffs to the Public Utilities Regulatory Authority (PURA) for approval. These program requirements are to include the subscriber credit rates, consumer protections for subscribers, and a maximum 20-year term length. Subscribers are to be limited to low and moderate income customers, small business customers, state or municipal customers, commercial customers, and residential customers who can demonstrate that they are unable to utilize the net metering successor tariff to be developed. At least 10% of the total capacity of each shared clean energy facility is to be reserved for low-income customers, in addition to a requirement that at least 10% of each facility's capacity must be reserved for low or moderate income customers or low-income service organizations. DEEP is allowed to provide preference for projects that serve low-income customers or benefit customers in environmental justice communities, and DEEP is also allowed to create incentives and financing mechanisms for low-income customers and limit commercial customer participation in each facility to 50%. The PURA opened a proceeding in June 2018 to review the requirements of the new legislation and develop a strategy and procedural roadmap for implementation. Technical meetings were held in July and August 2018. The tentative schedule has the DEEP submitting program requirements and tariff proposals by July 2019.	Docket No. 18-06-15 S.B. 9 (2018)
DC	The Public Service Commission is examining interconnection rules in Formal Case No. 1050. A September 2018 order in this rulemaking established a Net Energy Metering Working Group to address system upgrade costs related to the interconnection of community renewable energy facilities (CREFs), review the Commission's current net metering rules, and propose CREF-specific rules changes for the Commission's consideration. Another decision, issued later in September in Formal Case No. 1130 additionally tasked the Net Energy	Formal Case No. 1050 Order No. 19676 Order No. 19692

	Metering Working Group with considering whether the system capacity limit should be increased beyond 100% of a customer's historical usage. The working group met in December 2018 and February 2019. A third meeting is scheduled for April 18, 2019.	
IL	The Future Energy Jobs Act, which went into effect in June 2017, created a community renewable generation program. In September 2017, the Illinois Power Agency (IPA) published its Long-Term Renewable Resources Procurement Draft Plan, which sets out details of the community solar program. Community solar projects are included in the adjustable block purchasing program for renewable resources and community solar subscribers are eligible for net metering, with IOUs being required to submit community solar net metering tariffs by September 27, 2017. The plan also describes a low-income community solar incentive plan that provides extra funding of $69.23-$129.56 per REC (depending on utility and total capacity of the project) for community solar projects subscribed to by low-income customers. The plan also includes a competitive-bid procurement process for low-income community solar pilot projects, which will be a separate program from the incentive program. A final version of the plan was filed in December 2017, and the plan was adopted in early April 2018. In May 2018, the Commission issued an amendatory order, slightly changing the original order to allow the IPA to investigate possible cost savings from co-location of projects of total size larger than 2 MW and to include such projects in REC pricing tiers. In June 2018, Commonwealth Edison appealed the Commission's order to the Appellate Court of Illinois, Second Judicial District. In August 2018, the IPA published the final version of the long-term plan incorporating the changes made by the Commission. In December 2018, Commission Staff submitted a report to the Commission on the standards, process, and timing for review of the Adjustable Block Program and Illinois Solar for All batch contract/confirmation approval. In late March 2019, the Illinois Power Agency filed a petition to reopen the docket and requested clarification of its authority to conduct a second procurement event for RECs from new brownfield PV projects.	Docket No. 17-0392 IPA Long-Term Renewable Resources Procurement Plan Final Order
	In August 2018, the Illinois Power Agency filed a petition for approval of its Supplemental Funding Plan for the Illinois Solar for All program, a low-income solar incentive program aimed at encouraging development of distributed solar and community solar projects that will benefit low-income residents. An order approving the plan was issued in October 2018. Stakeholder engagements for the program began in November 2018 and continued throughout the first quarter of 2019.	Docket No. 18-1457 Solar for All Program Website
LA	In December 2015, the Louisiana Public Service Commission (PSC) initiated a two-phase rulemaking proceeding to I) modify the state's current net metering rule once a utility reaches the net metering aggregate cap, and II) examine appropriate changes to solar policies in Louisiana. In November 2017, as part of Phase II of the proceeding, the PSC staff published proposed modified net metering rules. The proposed rules also allow for community DG facilities up to 300 kW, which will be compensated at the avoided cost rate for any excess generation sold to the utility. Comments were filed in January 2018, and an open session was held in February 2018. The Commission Staff	Docket No. R-33929 Final Proposed DG Rules (Part 1) Final Proposed DG Rules (Part 2)

	filed final proposed rules in January 2019, which include most of the same provisions as the previous version of proposed rules.	
	In June 2018, the New Orleans City Council opened a rulemaking proceeding to establish rules for community solar projects. The City Council's Utility Advisors also published a white paper on community solar and shared DERs in June. The Advisors recommend that: (1) both utilities and third parties be allowed to develop community solar projects, (2) each project must have at least three participants, (3) each participants may be allowed to subscribe to no more than 40% of the project capacity, (4) 30% of program capacity be reserved for facilities providing at least 10% of output to low-income subscribers, (5) no minimum subscription amount be applied to low-income customers, (6) solar, solar plus storage, and other DERs be considered; (7) projects be limited to 2 MW; (8) an aggregate program cap of 5% of the utility's annual peak MW (approximately 55 MW) be established for the first three years; (9) bills credits be set at a rate equal to the avoided capacity, energy, and other directly quantifiable costs; and (10) RECs should be owned by the subscribers. The white paper includes additional recommendations of the Advisors. An advisors' report with revised recommendations was filed, and the Utility, Cable, Telecommunications, and Technology Committee passed a resolution establishing rules in December 2018. The revised rules passed in December require 50% of the program capacity to be reserved for community solar facilities providing at least 30% of their output to low-income subscribers. The rules include the aggregate cap, system size limit, and participant credit rates (a rate reflecting avoided energy and capacity costs) as proposed. The Committee approved an individual participation limit of 100% of the customer's annual baseline energy use. The Alliance for Affordable Energy filed comments recommending that the City Council reject the credit mechanism in the resolution, and Entergy New Orleans filed a response disagreeing with the Alliance's recommendations.	City Council Docket No. UD-18-03 Resolution R-18-538
MD	H.B. 683 and S.B. 520 make several changes to the community solar pilot program. The bills establish that there is no limit to the maximum number of subscribers to a project, extend the expiration date of the program until December 31, 2024 at the earliest, extend the due date for the Commission's report on the pilot to July 1, 2022, and suggests that the annual capacity limits for each program category should increase throughout the duration of the program. H.B. 683 passed the House and Senate in March 2019.	H.B. 683 (P2) S.B. 520 (P2)
MI	In October 2018, the Michigan Public Service Commission issued orders in Dockets U-18351 and U-18352 (which primarily concern green tariff programs proposed by Consumers Energy Company and DTE Electric, respectively) directing Commission Staff to conduct a stakeholder workgroup to examine opportunities for and barriers to third-party community energy projects and integration of these projects into utility planning and procurement processes. Workgroup meetings took place in January and March 2019, and additional meetings are scheduled for May and July 2019.	Third Party Community Energy Projects Workgroup
MN	Minnesota has an ongoing proceeding related to community solar gardens. A September 2016 decision transitioned the credit rates for	Docket No. 13-867

	subscribers from the retail rate to the value of solar rate. The Commission also called on the Department of Commerce to comment on whether the credit rate should be adjusted with a positive or negative adder for seven categories, some location-specific and others customer-specific. The Department of Commerce filed its recommendations in March 2017, suggesting that only residential subscribers receive an adder to make community solar more attractive. The Commission issued an order related to the proposal in December 2017, declining to approve or deny the Department's proposal. Instead, the Commission asked Xcel Energy for an analysis of the potential rate impact of the Department's proposal, and how a solar carve-out for community solar projects would be implemented and enforced. Xcel Energy provided its analysis in February 2018. After receiving comments and reply comments, the Commission scheduled a meeting for October 11th to discuss Xcel's analysis. The Commission then issued an order in November 2018, approving a $0.015/kWh adder to the value of solar rate for residential subscribers. The adder will be available for a two-year term as a pilot, and available to projects with a 2019 or 2020 value of solar vintage year. Also in this proceeding, Xcel filed its 2019 Value of Solar rate in August 2018. The proposed rate is a decrease from the rate used in previous years and would negate the adders applied by the Commission's November order. In December 2018, Xcel filed for approval of its proposed Community Solar Garden (CSG) tariffs. In February 2019, the Commission issued an order denying petitions for reconsideration of the November 2018 order. The Commission issued a second order in February to clarify that its approval of a decrease in the value of solar rate was inherent within its November order. The Commission issued an order in March 2019 approving Xcel's 2019 Value of Solar Rate as modified in the order to account for a revised consumer price index value and an alternative methodology for calculating capacity factor.	Order
MT	H.B. 513 increases the eligible size limit for a community renewable energy project from 25 MW to 35 MW and also allows energy storage projects of any size to be considered community renewable energy projects. The House passed the bill in February 2019.	H.B. 513 (P1)
NC	H.B. 589, enacted in July 2017, authorizes and establishes rules for community solar. The proposed legislation directs Duke Energy Carolinas and Duke Energy Progress to file plans for community solar programs limited to 20 MW. Each community solar facility may be up to 5 MW, and must have at least five subscribers. A single subscriber may not have more than a 40% interest in the facility, each subscription must be at least 200 W, and a participant may only subscribe up to 100% of their maximum annual peak demand. Community solar facilities must be located in the offering utility's service territory, and participants must be located in the same county or contiguous county to the community solar facility (exceptions for distances up to 75 miles may be granted by the Utilities Commission if it is in the public interest). Participants will be credited at the utility's avoided cost rate, and the program must hold non-participating customers harmless. Subscribers must also be offered the option to own the RECs associated with the energy produced by the community solar facility.	H.B. 589 (2017) Docket E-100 Sub 155 (Rule Development) Order and Rule R8-72 Docket E-2 Sub 1169 (Utility Proposals) Proposed Community Solar Program Plan

	In late August 2017, the North Carolina Utilities Commission (NCUC) initiated a rulemaking to implement the legislation, and the NCUC adopted Rule R8-72 in December 2017. In January 2018, Duke Energy Carolinas and Duke Energy Progress filed their joint petition for approval of a community solar program. The program plans include an upfront payment for participants (estimated around $500), who will be credited at the applicable avoided cost rate, following the methodology approved by the Commission at the time the companies open the program to participants. After a round of comments, Duke filed a revised program plan in June 2018. The revised tariffs reflect a move to a subscription model and the inclusion of monthly charges and credits on the customer bill, as well as a modified procedure for customers to subscribe to the program. The revised tariffs also increase the size of a block from 220 Watts to 1 kW and clarify that monthly subscription credits will be variable based on the actual production of the facility. The Commission approved the revised program plan and tariffs in April 2019.	Revised Community Solar Program Plan Order
NH	S.B. 165 allows all hosts of group net metering projects to elect to receive credits on the host's and each member's electric bill according to the specified percentages, rather than all credits going to the host to distribute. Currently a limited number of low-moderate income community solar projects are allowed to do this. The bill also provides a 3 cent per kWh addition for low-moderate income community solar projects and requires each utility to have at least three new low-moderate income community solar projects each year beginning in 2020. The Senate passed an amended version of the bill in March 2019. The amended version extended the deadline for the Commission to report on the costs and benefits of low-moderate income community solar projects from December 31, 2019 to June 1, 2020. The amended version also reduces the number of low-moderate income community solar projects that utilities must have in their service territory each year from three to two.	S.B. 165 (P1)
NJ	A.B. 3723, signed into law in May 2018, creates a Community Solar Energy Pilot Program. The bill directs the Board of Public Utilities to establish a capacity limit for individual projects to a maximum of 5 MW, an annual aggregate capacity limit for the pilot program, geographic limitations for projects and participants, a minimum number of participants per project, the participant bill credit rate, standards to limit land use impact of projects, ways to provide access to low and moderate income customers, standards to ensure residential and commercial customers may participate, interconnection standards, and provisions to minimize distribution system impacts. The bill also authorizes the Board to restrict projects to those located on brownfields, landfills, areas designated in need of redevelopment, in underserved communities, or on commercial rooftops. Within 3 years of adoption of final program rules, the pilot program is to be converted to a permanent program. At this point, the Board is to adopt rules for the permanent program and standards for projects owned by utilities, special purpose entities, and non-profits. These rules are also to limit the project size limit to a maximum of 5 MW, establish a goal of at least 50 MW in aggregate community solar capacity per year, establish a method for determining participant bill credit rates, establish and require	A.B. 3723 (2018) Community Solar Energy Pilot Program Community Solar Energy Pilot Program Rule Proposal

	transferability, portability, and buy-out provisions for participants. The Board formed a community solar stakeholder group, with information available on its website. In September 2018, the Board of Public Utilities released proposed community solar pilot program rules, which were published in the New Jersey Register in early October. The proposed rules include retail rate bill credits, a 40% low-to-moderate income customer carve-out, and a maximum program cap of 75 MW for year 1 and a minimum of 75 MW of program capacity for years 2 and 3. In November 2018, a draft of the Community Solar Program Application form, Subscriber Organization Registration form, and Subscriber Disclosure form were published for public comment. Comments were accepted until December 21, 2018. The Board of Public Utilities approved the pilot program rules in January 2019. The final rule was published in the New Jersey Register in February 2019.	
NM	H.B. 210 and S.B. 281 establish a community solar program. Community solar projects may be up to 10 MW (AC) and must be located in the service territory or connected to the distribution system of an IOU in the state. Community solar projects must have at least 10 subscribers, with no single subscriber accounting for over 60% of the project's capacity. No more than 60% of the capacity of community solar projects may be allocated to subscriptions over 25 kW. Energy storage projects may also be co-located with community solar projects. Community solar projects may be owned by "subscriber organizations" (municipalities; counties; Indian nations, tribes, and pueblos; for-profit and non-profit entities authorized to transact business in New Mexico or within the jurisdiction of Indian nations, tribes, or pueblos; low-income service organizations and affordable housing providers), third parties contracting with subscriber organizations, and unregulated affiliated interests of IOUs. IOUs may also own and operate community solar projects under certain conditions. The bills specify that owners and operators of and the subscribers of community solar projects will not be considered public utilities based on their participation in the project. Bill credits are to be determined by deducting the distribution cost component from the retail rate and considering any reasonably determinable benefits, such as REC value, reduction in the need for capital investments in generation resources, reduction in energy or capacity costs, reduction in line losses, and system integration benefits from including energy storage with projects. Utilities may recover interconnection costs and system integration costs from subscriber organizations. IOUs are to file applications for community solar plans and rates by February 1, 2020. The bills specify that there is not to be a limit on the number or capacity of community solar projects. The bills also direct the Public Regulation Commission to encourage low-income customer participation through mechanisms, such as capacity targets for low-income subscriptions, allowing low-income energy assistance program funds to be used for low-income community solar participation, and allowing interconnection priority for community solar projects serving low-income customers. The House passed H.B. 210, in February 2019, but the bill died at the end of the legislative session.	H.B. 210 (D) S.B. 281 (D)
NY	In March 2017, the Public Service Commission (PSC) issued an order addressing the steps to transition from traditional net metering to a Value of Distributed Energy Resources (VDER) tariff. In March 2017, community solar, remote net-metered projects, and large distributed	Docket No. 15-02703/15-E-0751

energy projects began to be compensated through the Phase I Value Stack tariff that includes energy (based on LMP), capacity, environmental, and demand reduction credits. Community distributed generation (CDG) projects are eligible for market transition credits (MTCs) that decline as certain thresholds of installed capacity (tranches) are reached. An organizational conference on Phase II of the VDER proceeding was held in May 2017. Phase II includes discussion of several topics, including improvements and modifications to the value stack (including components related to the bulk system, distribution system, and societal values). In June 2017, the PSC established three working groups: one each to cover the value stack, rate design, and low to moderate income issues. In December 2017, the Commission Staff published a report on the low-income community DG proposal, which includes the positions of the intervenors and the staff's analysis on (1) the interzonal credit, which would provide benefits to low-income customers from projects interconnected in other load zones, (2) the bill discount pledge program, providing a direct incentive to subsidize subscription prices through utility low-income funds, (3) the role of NYSERDA programs, (4) the loss reserve, and (5) environmental justice location incentives. In May 2018, PSC Staff proposed to reduce the subscription size necessary for participation in Community Distributed Generation from 1000 kWh to 500 kWh. In September 2018, the Commission issued an order keeping the minimum subscription size at 1000 kWh and making interzonal crediting available for CDG projects. Community distributed generation (CDG) projects are eligible for market transition credits (MTCs) that decline as certain thresholds of installed capacity (tranches) are reached. In July 2018, Commission Staff released a white paper with recommendations for compensation of CDG projects beyond current tranches. Staff recommendations differed for different utility service territories; Staff recommended a reduction in MTC rates for National Grid, NYSEG, and RG&E service territories for new Tranches 5 and 6 (3 cent per kWh and 2.5 cent per kWh, respectively), an increase in MTC rates for Con Edison service territory for Tranches 1, 2, and 3, and a reduction in MTC rates and reallocation of credit funding responsibility from utility ratepayer funds to state funds for Orange and Rockland and Central Hudson service territories. Technically, new CDG projects in Orange and Rockland and Central Hudson territory would stop receiving MTCs, but would have those credits replaced with state incentives equivalent to the Tranche 5 and 6 levels for the other territories, with some of the incentive amount coming from the Value Stack mechanism. The PSC continues to consider modifications to the VDER tariff.	Docket No. 15-E-0082 Matter No. 17-01278 NYSERDA VDER Resources
This proceeding was originally opened in 2015 to establish a Community Distributed Generation (CDG) program, with Phase I of that program taking place between October 19, 2015, and April 30, 2016. Although many CDG projects were initiated under this program, no projects were undertaken in the low-income category, which had been an area of priority for the program. In June 2017, a working group was	Docket No. 15-00348/15-E-0082

	established to address low and moderate income (LMI) customer programs under Phase II of the Value of Distributed Energy Resources (VDER) process. One topic addressed by this working group was LMI participation in CDG programs. In December 2017, the Public Service Commission Staff issued a report proposing several measures to increase LMI participation in CDG projects, including the creation of a bill discount pledge program, income verification services for CDG project customers, and creation of a loss reserve fund to support LMI-focused CDG projects. In July 2018, the Commission issued an order approving the three programs recommended in the Staff report. In August 2018, Sandy Hollow Power Company filed a petition asking the Commission to enable VDER credits for CDG projects to be given to the utility rather than the customer, in order to facilitate participation in CDG projects by low-income customers, for whom the small credit amounts and administrative difficulties associated with collecting the credit may inhibit participation in CDG projects. In July 2018, PSC Staff published a white paper proposing several changes to CDG rules. In September 2018, the PSC issued an order based on the staff white paper; the order makes all proposed VDER-eligible technologies eligible for CDG, allows interzonal crediting for CDG projects using Value Stack compensation, and retains the 1,000 kWh minimum subscription size for CDG. The July white paper also proposed expanding incentives for CDG in utility territories where existing incentives have been fully subscribed, and in October 2018, the PSC issued a request for comments on this proposal. In November 2018, several environmental organizations filed comments supporting the proposal. In early December, National Grid reported that Tranche 1 of its CDG program was filled. In December, the joint utilities filed an implementation plan for the Bill Discount Pledge Program to assist LMI customers in receiving CDG program subscriptions. Under the Bill Discount Pledge Program, an LMI customer may choose to use the bill discount toward purchasing shares of CDG, which will in turn lower their utility bills. The utility will pay the CDG owner for the LMI customer's subscription. The City of New York filed comments on the implementation plan in early April 2019; the comments general support the plan, but call for stakeholder comment on proposed agreements between CDG hosts and utilities and request that customers be notified of any changes in eligibility for the program.	
OR	S.B. 1547 of 2016 established a community solar program for the state. The legislation set basic criteria and directed the Public Utility Commission (PUC) to establish rules for the program, which must require utilities to enter into 20-year power purchase agreements with certified projects and incentivize customers to participate while minimizing cost shifts and financial burdens. The PUC adopted community solar rules in June 2017. While the rules provide guidance on many aspects on community solar, certain issues will not be fully addressed until the Program Implementation Manual is developed and adopted by the PUC. The PUC is also continuing to develop the Resource Value of Solar (see DG Valuation section), which will be the bill credit basis for community solar participants. There are multiple implementation actions that must be taken before the community solar program is launched, including selection of a third-party administrator for the program. In September 2017, the PUC	S.B. 1547 (2016) Docket No. AR 603 (Rulemaking) Docket No. UM 1930 (Implementation)

	approved the Staff's recommendation to commence a stakeholder process to identify and scope all of the implementation actions that must be taken. The PUC hosted a community solar workshop in October 2017, where the remaining implementation actions were discussed. In February 2018, the PUC issued an order accepting the staff's recommendation to continue investigations directly related to rulemaking in the existing docket, but also open a new docket to explore program implementation. The PUC issued an order in the new docket in March 2018 stating its interest in adopting a temporary alternative credit rate structure while the RVOS is continuing to be developed, and directed the staff to present no less than two proposals in April. The Staff presented three options: a simple retail rate option, an adjusted retail rate option, and an adjusted RVOS option. Both of the "adjusted" rates would be adjusted by applying several adjustment factors to reflect the guiding principles developed by the Staff, which include simplicity, accessibility, minimization of cost-shifting, locational value, and ease of transition to an RVOS-based rate. In May 2018, the Commission issued an order accepting the Staff's simple retail rate proposal as an interim bill credit rate for the first 25% of each utility's initial capacity tier. The Commission remains undecided on the credit rate for the remaining 75% of the initial capacity tier. The Staff filed status update reports in July, September, November, and February. The Staff issued a notice of intent to award a contract to Energy Solutions to serve as the program administrator for the community solar program. The February 2019 staff report provides updates on the competitive selection of the program administrator, the process for utilities to recover program start-up costs, the Commission decision concluding Phase II of the RVOS docket, and the community solar implementation subgroups.	
RI	In December 2018, Energy Development Partners (EDP) LLC filed a petition before the Public Utilities Commission for a declaratory judgment seeking a determination that for a net metering financing arrangement with a public entity the requirement that the "net metering resource is located on property owned or controlled by the public entity" is satisfied when the public entity has an irrevocable license over the property. Site control must be satisfied before a third party owned system can qualify as an eligible net metering system. In this particular case, EDP is unable to provide a ground lease or an easement to the public entity, given restrictions in place on the land, but it can grant an irrevocable license. EDP is seeking declaratory judgement that an irrevocable license satisfies the definition of "property owned or controlled by the public entity" under the net metering act. National Grid and the Division of Public Utilities and Carriers filed comments in February 2019, supporting EDP's petition. At the Commission's February 15th open meeting, the Commission approved the petition, declaring that an irrevocable license qualifies for site control.	Docket No. 4917
SC	H.B. 3659 encourages all electric service providers to consider offering community solar programs. Within 60 days after the effective date of the bill, the Public Service Commission must open a docket for each utility to review the community solar programs established pursuant to Act 236 of 2014 and to solicit status information on existing programs from the utilities. Within 180 days after the Commission opens the docket, the utilities must update their report on their existing programs	H.B. 3659 (P1)

	and may propose new programs. Participating customers must bear the burden of any reasonable and prudent costs associated with participating in a community solar program; however, the Commission will still promote access to solar energy projects for low and moderate income customers. A utility may not charge any non-participating customers for any costs associated with the community solar program.	
UT	H.B. 411 is the Community Renewable Energy Act. Utilities with over 200,000 retail customers in the state may file applications for community renewable energy programs, with projects being acquired through a competitive solicitation process. The utility may own the resource as long as including this option in a solicitation is in the interest of both participating and non-participating customers. The program must not result in any cost or benefit shift to non-participating customers, and the utility's application must include a plan established by the participating community addressing low-income programs and assistance. The rate for participating customers is to consider the quantifiable costs and benefits. Participating customers must be located in a municipality or county that adopts a resolution by December 31, 2019 to achieve 100% renewable energy by 2030. The Governor signed the bill into law in late March 2019. The Public Service Commission opened a proceeding in early April to implement the legislation. A scheduling conference will be held on April 23, 2019.	H.B. 411 (E) Docket No. 19-R314-01

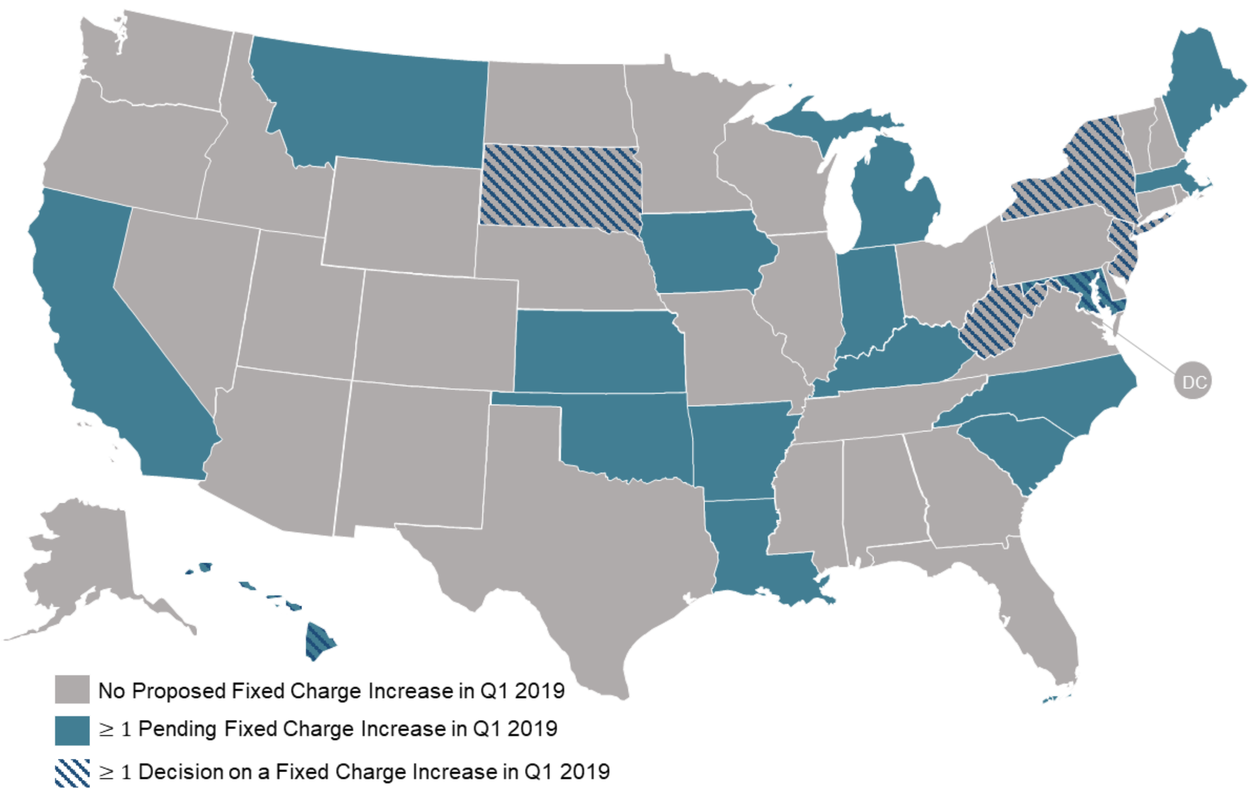
FIXED CHARGES AND MINIMUM BILLS

Key Takeaways:

- In Q1 2019, 32 utility requests to increase residential fixed charges or minimum bills by at least 10% were considered in 20 states.
- Seven fixed charge decisions were made in Q1 2019, and four new requests to increase fixed charges were initiated during the quarter.
- Overall, the median increase requested was $3.65 per month, and the median percentage increase requested was 37% (average of 79%).[‡] Proposals ranged from monthly increases of $1.12 to $19.94.

Utility requests to increase residential fixed charges continued in Q1 2019, with 32 utility requests in 20 states to increase residential fixed charges or minimum bills by at least 10% pending or decided during the quarter.

Figure 8. Proposed Increases to Residential Fixed Charges (Q1 2019)

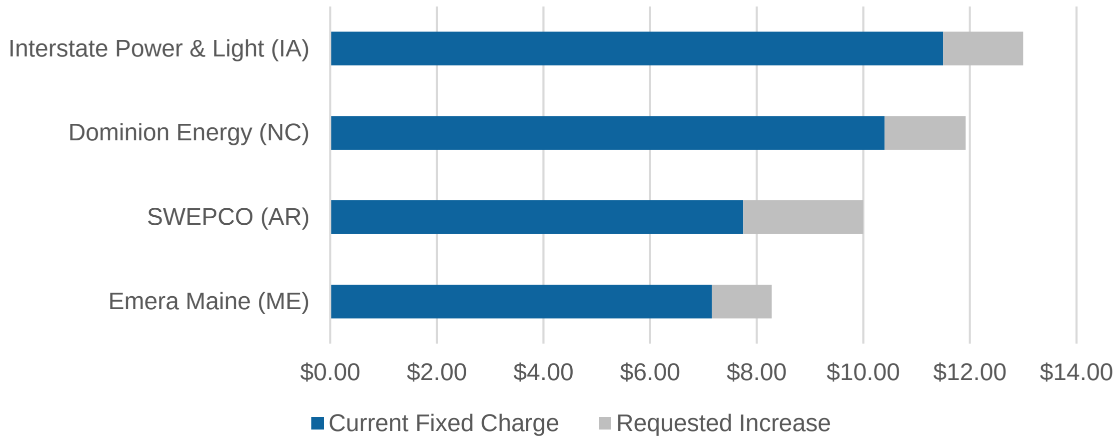


The median percentage increase requested among all pending and decided proposals was 37% during Q1 2019, while the average was 79%. However, many of these proposals were initiated

[‡] Proposed increases for customers of PG&E and SCE are omitted from the percentage increase calculation because presently those companies do not have residential fixed charges, only minimum bills.

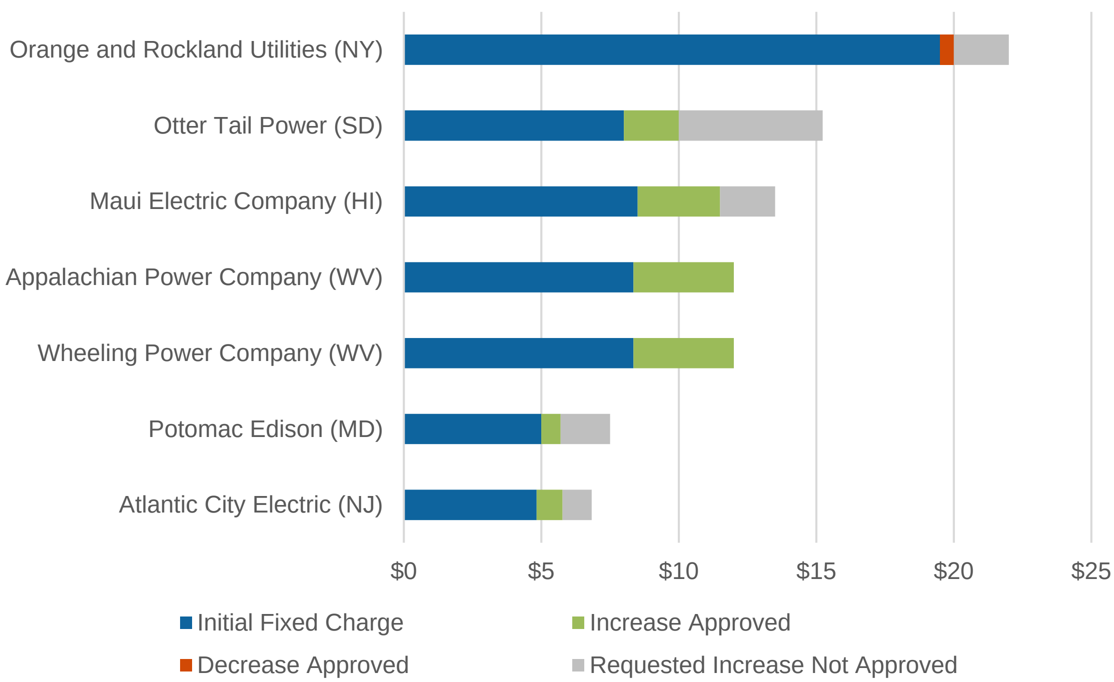
prior to Q1 2019, and only four utilities proposed new fixed charge increases of at least 10% this quarter (see Figure 9). Among these new proposals, the average requested increase was $1.60, or 18%. This is notably lower than the overall average requested increase represented by all of the pending and newly decided proposals, which was 79%.

Figure 9. New Residential Fixed Charge Increase Proposals in Q1 2019



Seven decisions were made during Q1 2019, with two utilities (*Appalachian Power – WV and Wheeling Power Company – WV)* receiving their full requested increases and four utilities *(Maui Electric Company – HI, Potomac Edison – MD, Atlantic City Electric – NJ, and Otter Tail Power – SD)* receiving partial increases. One utility's *(Orange and Rockland Utilities – NY)* fixed charge was reduced as part of a settlement agreement.

Figure 10. Residential Fixed Charge Decisions in Q1 2019



The average increase granted in Q1 2019 was 26%, with utilities receiving on average 48% of their requested increase. There were 25 requests pending at the end of Q1 2019 to increase residential fixed charges or minimum bills. The largest pending requests, by percent, are: (1) Southern California Edison ($6.54; 696%) (2) Duke Energy Carolinas – SC ($19.71; 238%), (3) Duke Energy Progress – SC ($19.94; 220%), (4) Energy New Orleans ($10.41; 129%), and (5) Oklahoma Gas & Electric – OK ($9.00; 69%).

Table 7. Residential Fixed Charge Decisions (Q1 2019)

State	Utility	Amount of Increase Granted	% Increase Granted	% of Initial Request Granted
HI	Maui Electric Company	$3.00	35%	60%
MD	Potomac Edison	$0.70	14%	28%
NJ	Atlantic City Electric	$0.94	19%	47%
NY	Orange and Rockland Utilities	-$0.50	-2.5%	-25%
SD	Otter Tail Power	$2.00	25%	28%
WV	Appalachian Power Company	$4.00	44%	100%
WV	Wheeling Power Company	$4.00	44%	100%
Q1 2019 MEDIAN		**$2.00**	**25%**	**47%**
Q1 2019 AVERAGE		**$2.02**	**26%**	**48%**

Another notable action related to fixed charges was the North Carolina Public Staff's publication of a report on the minimum system methodology (a methodology often used to determine fixed charges) in March 2019. The study was conducted pursuant to an order issued last year in Duke Energy Carolinas' general rate case. The Public Staff's report finds 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.

Figure 11. Active Proposals to Increase Residential Fixed Charges in Q1 2019

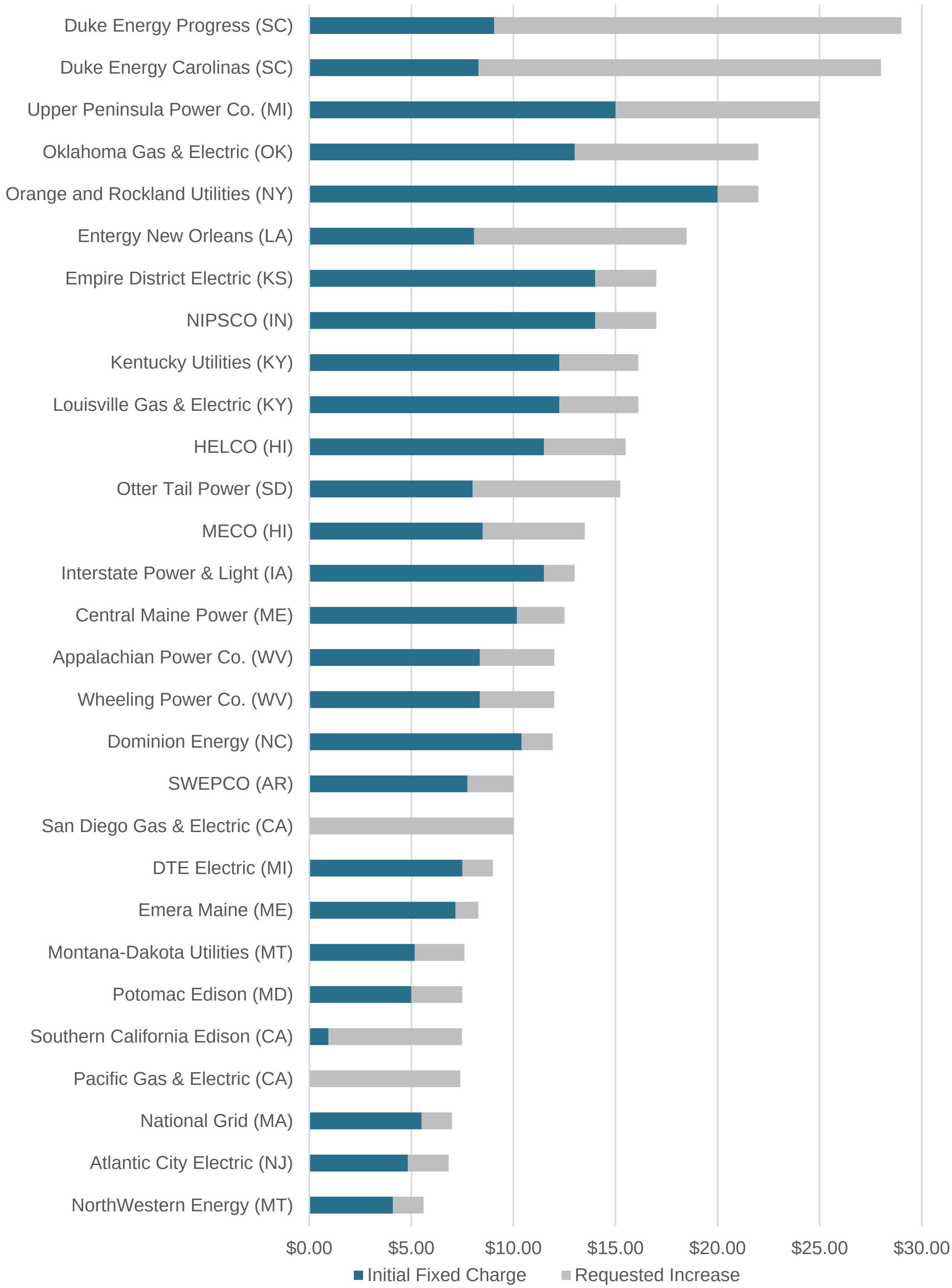


Table 8. Updates on Increases to Residential Fixed Charges (Q1 2019)

State	Utility	Monthly Residential Fixed Charge			Description	Source
		Existing	Proposed	Approved		
AR	Southwestern Electric Power Company (SWEPCO)	$7.75	$10.00	*Pending*	In February 2019, Southwestern Electric Power Company requested an increase in its residential monthly fixed charge.	Docket No. 19-008-U
CA	Pacific Gas & Electric	$0.00	$7.40	*Pending*	Pacific Gas & Electric (PG&E) applied for a fixed charge to be implemented in two phases, starting at $3.70 for one year, then increasing to $7.40 in the second year. The California Public Utilities Commission issued a resolution in January 2018, making a preliminary determination in favor of a hearing on PG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	Docket No. 17-12-011
	Pacific Gas & Electric	$10.00 (Min. Bill)	$15.00 (Min. Bill)	*Pending*	Pacific Gas & Electric (PG&E) applied for an increase in its monthly minimum bill. The California Public Utilities Commission	Docket No. 17-12-011

				issued a resolution in January 2018, making a preliminary determination in favor of a hearing on PG&E’s request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility’s TOU rates. Phases II and III will address the proposed rate designs, including the proposed minimum bill increase. A decision was issued for Phase IIa in December 2018; this decision stated that the minimum bill issue will be addressed in Phase III of the proceeding.	
San Diego Gas & Electric	$0.00	$10.00	*Pending*	San Diego Gas and Electric (SDG&E) applied for a $10 monthly fixed charge in a December 2017 rate design window filing. The California Public Utilities Commission issued a Resolution in January 2018, making a preliminary determination in favor of a hearing on SDG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility’s TOU rates. Phases II and III will	Docket No. 17-12-013

				address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	
San Diego Gas & Electric	$10.00 (Min. Bill)	$37.25 (Min. Bill)	*Pending*	San Diego Gas and Electric (SDG&E) applied for a minimum bill increase in a December 2017 rate design window filing. The California Public Utilities Commission issued a Resolution in January 2018, making a preliminary determination in favor of a hearing on SDG&E's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed minimum bill increase. A decision was issued for Phase IIa in December 2018; this decision stated that the minimum bill issue will be addressed in Phase III of the proceeding.	Docket No. 17-12-013
Southern California Edison	$0.94*	$7.48*	*Pending*	Southern California Edison (SCE) applied for an increase in its monthly fixed charge in a December 2017 filing. The California Public Utilities Commission issued a Resolution in January 2018, making a preliminary	Docket No. A17-12-012

					determination in favor of a hearing on SCE's request. The dockets for PG&E, SCE, and SDG&E were consolidated in January 2018, and a prehearing conference was held in February. Parties at the prehearing conference agreed to a three-phased approach to resolve all issues. Phase I was expedited, and a May 2018 order established the start date for each utility's TOU rates. Phases II and III will address the proposed rate designs, including the proposed fixed charge increase. A decision was issued for Phase IIa in December 2018; this decision stated that the fixed charge issue will be addressed in Phase III of the proceeding.	
HI	Hawaii Electric Light Company	$11.50	$15.50	*Pending*	In December 2018, Hawaii Electric Light Company proposed an increase in its residential monthly fixed charge.	[Docket No. 2018-0368]()
	Maui Electric Company (MECO)	$8.50	$13.50	$11.50	In October 2017, Maui Electric Company (MECO) proposed an increase in its residential monthly fixed charge. In a February 2018 order, the Commission instructed MECO to submit revised schedules to reflect the effects of the corporate tax cut enacted by Congress. MECO's revised schedules include the same fixed charge increase as its original proposal. A settlement agreement between MECO and the Consumer Advocate filed in June 2018 includes a smaller increase in the fixed charge to $11.50. A March 2019 order approved the June 2018 settlement.	[Docket No. 2017-0150]() [Order]()

	Maui Electric Company (MECO)	$18.00 (Min. bill)	$25.00 (Min. bill)	$25.00 (Min. bill)	In October 2017, Maui Electric Company (MECO) proposed an increase in its residential monthly minimum bill. In a February 2018 order, the Commission instructed MECO to submit revised schedules to reflect the effects of the corporate tax cut enacted by Congress. MECO's revised schedules include the same minimum bill increase as its original proposal. A settlement agreement between MECO and the Consumer Advocate filed in June 2018 retains the increase in the minimum bill to $25.00. A March 2019 order approved the June 2018 settlement.	Docket No. 2017-0150 Order
IA	Interstate Power & Light	$11.50	$13.00	*Pending*	In March 2019, Interstate Power & Light, as part of a general rate case, proposed an increase in the monthly residential fixed charge.	Docket No. RPU-2019-0001
IN	Northern Indiana Public Service Company (NIPSCO)	$14.00	$17.00	*Pending*	In October 2018, as part of a general rate case, Northern Indiana Public Service Company (NIPSCO) requested an increase in its residential monthly fixed charge from $14.00 to $17.00. An evidentiary hearing is scheduled for April 2019.	Docket No. 45159
KS	Empire District Electric	$14.00	$17.00	*Pending*	In December 2018, as part of a general rate case, Empire District Electric Company requested an increase in its residential monthly fixed charge from $14.00 to $17.00.	Docket No. 19-EPDE-223-RTS
KY	Kentucky Utilities	$12.25	$16.12*	*Pending*	In September 2018, Kentucky Utilities proposed an increase in its residential fixed charge. The charge would go from a monthly rate of $12.25 to a daily rate of $0.53 (averaging $16.12	Docket No. 2018-00294

					per month). A settlement agreement was filed in March 2019; however, the customer charge issue was not addressed in the settlement.	
	Louisville Gas & Electric	$12.25	$16.12*	*Pending*	In September 2018, Louisville Gas & Electric proposed an increase in its residential fixed charge. The charge would go from a monthly rate of $12.25 to a daily rate of $0.53 (averaging $16.12 per month). A settlement agreement was filed in March 2019; however, the customer charge issue was not addressed in the settlement.	Docket No. 2018-00295
LA	Entergy New Orleans	$8.07	$18.48	*Pending*	In July 2018, Entergy New Orleans filed a general rate case application, but withdrew the application shortly thereafter. Entergy refiled its rate case application in September 2018, which includes an increase in the residential monthly fixed charge.	City Council Docket No. 18-07
MA	National Grid	$5.50	$7.00	*Pending*	In November 2018, National Grid proposed an increase in its residential monthly fixed charge.	Docket No. 18-150
MD	Potomac Edison	$5.00	$7.50	$5.70	In August 2018, Potomac Edison proposed an increase in its residential monthly fixed charge. A March 2019 order approved a smaller increase in the customer charge than requested.	Docket No. 9490
ME	Central Maine Power	$10.17	$12.50	*Pending*	In October 2018, Central Maine Power proposed an increase in its residential monthly fixed charge.	Docket No. 2018-00194
	Emera Maine	$7.02 (Avg., Min. bill)	$8.15 (Avg., Min. bill)	*Pending*	In March 2019, Emera Maine requested an increase in its residential	Docket No. 2019-00019

					monthly minimum bill. Emera is requesting an increase from $7.02 to $8.15 for its Bangor Hydro District and an increase from $7.30 to $8.41 for its Maine Public District.	
MI	DTE Electric	$7.50	$9.00	*Pending*	In July 2018, DTE Electric proposed an increase in its monthly residential fixed charge. A proposed decision filed in early March 2019 would reject the fixed charge increase.	Docket No. U-20162
	Upper Peninsula Power Company (UPPCO)	$15.00	$25.00	*Pending*	In September 2018, UPPCO proposed an increase in its monthly residential fixed charge. In early April 2019, parties indicated that they were close to reaching a settlement agreement.	Docket No. U-20276
MT	Montana-Dakota Utilities	$5.17*	$7.60*	*Pending*	In September 2018, Montana-Dakota Utilities proposed an increase in its daily basic service charge from $0.17 per day to $0.25 per day.	Docket No. D2018.9.60
	North-Western Energy	$4.10	$5.60	*Pending*	In September 2018, NorthWestern Energy proposed an increase in its residential monthly fixed charge.	Docket No. D2018.2.12
NC	Dominion Energy	$10.40	$11.92	*Pending*	In February 2019, Dominion Energy proposed an increase in its residential monthly fixed charge.	Docket No. E-22 Sub 562
NJ	Atlantic City Electric	$4.83	$6.83	$5.77	In August 2018, Atlantic City Electric proposed an increase in its residential monthly fixed charge. The Board of Public Utilities approved a settlement agreement in March 2019, which includes a smaller increase in the fixed charge.	ACE Petition (Docket No. ER18080925) Final Order

NY	Orange and Rockland Utilities	$20.00	$22.00	$19.50	In January 2018, Orange and Rockland Utilities requested an increase in its residential monthly fixed charge. Regulators approved a settlement agreement in March 2019, which reduces the fixed charge to $19.50.	Docket No. 18-00253/18-E-0067
OK	Oklahoma Gas & Electric	$13.00	$22.00	*Pending*	In December 2018, Oklahoma Gas & Electric proposed an increase in its residential monthly fixed charge.	Docket No. PUD-201800140
SC	Duke Energy Carolinas	$8.29	$28.00	*Pending*	In November 2018, Duke Energy Carolinas proposed an increase in its residential monthly fixed charge.	Docket No. 2018-319-E
	Duke Energy Progress	$9.06	$29.00	*Pending*	In November 2018, Duke Energy Progress proposed an increase in its residential monthly fixed charge.	Docket No. 2018-318-E
SD	Otter Tail Power Company	$8.00	$15.23	$10.00	In April 2018, Otter Tail Power Company proposed an increase in its residential monthly fixed charge. The Commission approved a settlement in March 2019, which increases the fixed charge to $10.00.	Docket No. EL 18-021
WV	Appalachian Power Company	$8.35	$12.00	$12.00	In May 2018, Appalachian Power requested an increase in its residential monthly fixed charge. The Commission approved the full requested increase in February 2019.	Docket No. 18-0646-E-42T
	Wheeling Power Company	$8.35	$12.00	$12.00	In May 2018, Wheeling Power requested an increase in its residential monthly fixed charge. The Commission approved the full requested increase in February 2019.	Docket No. 18-0646-E-42T

* Denotes that the utility uses a daily fixed charge for residential customers instead of a monthly fixed charge. All daily charges are converted into monthly charges for this table using the following formula: [(365 days/year)*($[fixed charge]/day)]/(12 months/year) = $[fixed charge]/month. If the charge varies by kWh consumption, it is assumed that the customer uses 900 kWh.

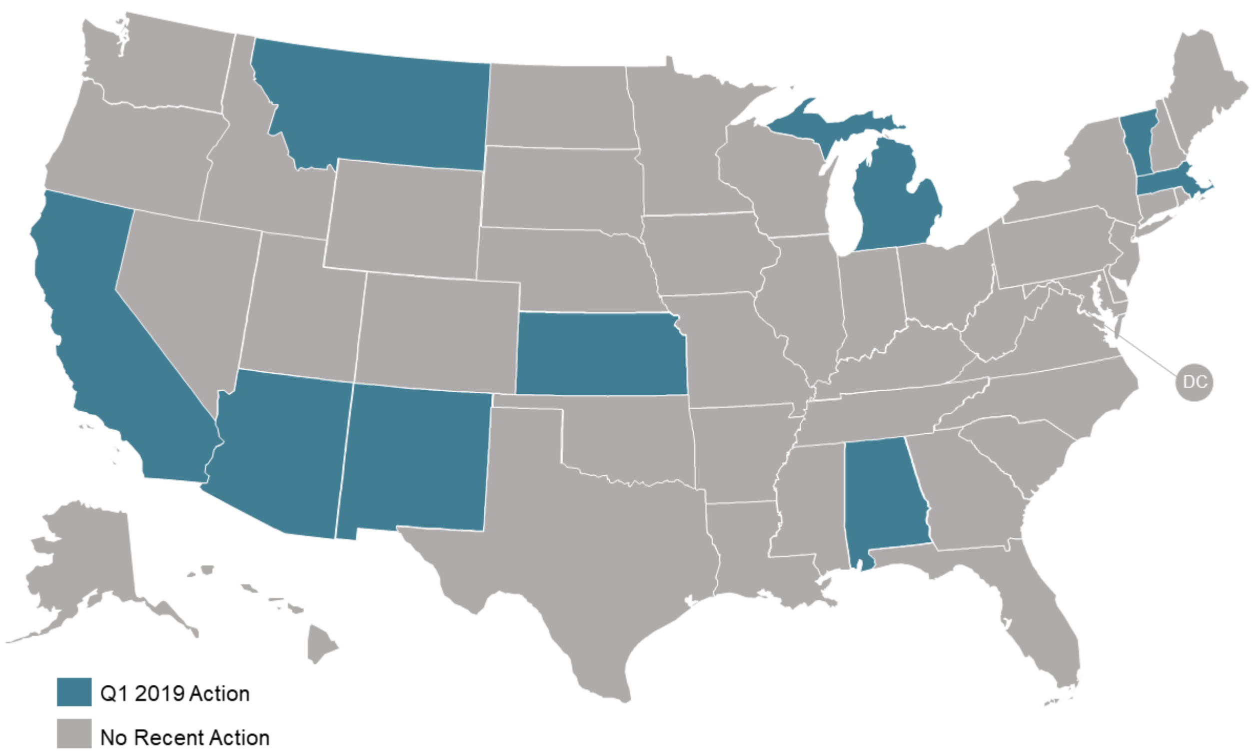
DEMAND AND SOLAR CHARGES

Key Takeaways:

- In Q1 2019, 13 actions related to demand charges or other charges on distributed generation customers were pending or recently decided in 9 states.
- Sacramento Municipal Utility District proposed a new Grid Access Charge, while Salt River Project's Board approved new fee options proposed by the utility.
- Legislation under consideration in several states would explicitly prohibit or allow additional fees to be applied to DG customers.

In Q1 2019, there were 13 actions related to demand or other distributed generation (DG) customer charges under consideration. Proposals to adopt new fees based on DG system capacity were the most common type of action during the quarter. Several state legislatures also considered bills addressing the authority of utilities and regulators to adopt additional fees for solar customers.

Figure 12. Action on Demand or Solar Customer Charges (Q1 2019)



Two utilities – Green Mountain Power and Sacramento Municipal Utility District (SMUD) – proposed new DG customer fees in Q1 2019. Both fees are based on DG system capacity, with SMUD's proposed charge ("Grid Access Charge") applying to all new DG customers and Green Mountain Power's applying only to new systems installed on specified circuits that have upgrades that need to be completed. Green Mountain Power's proposed fee is an upfront charge, as opposed to a monthly fee. SMUD withdrew its proposed Grid Access Charge in mid-April 2019.

Salt River Project's Board approved changes to the utility's DG customer charges in March 2019. Salt River Project will now offer two new tariff options for DG customers. One tariff includes a demand charge based on average daily demand during system peak hours, rather than monthly peak demand during system peak hours. The second tariff includes time-varying rates and no additional charges, but compensates customers at a lower fixed rate of 2.81 cents per kWh for energy exported to the grid.

Table 9. Summary of DG Fee Proposals (Q1 2019)

State	Utility	Type of Charge	Proposed Amount	Other Changes
AL	Alabama Power	DG Capacity Charge	$5.42 per kW	None
AZ	Salt River Project	Demand Charge (average daily demand)	$8.13 - $21.94 per kW	None
		No Charge	$0.00	DG Export Rate Reduction
CA	Sacramento Municipal Utility District	DG Capacity Charge	$11.00 per kW	None
MA	National Grid	Flat Charge	$4.20	None
MI	DTE Electric	DG Capacity Charge	$2.31 per kW	DG Export Rate Reduction, Fixed Charge Increase
	Upper Peninsula Power Company	DG Capacity Charge	Not Specified	DG Export Rate Reduction, Fixed Charge Increase
MT	NorthWestern Energy	Demand Charge (non-coincident)	$8.64 per kW	Fixed Charge Increase, New Customer Class
VT	Green Mountain Power	DG Capacity Charge	$75.00 per kW (one-time) for specified locations	None

Several state legislatures also addressed DG customer fees during Q1 2019. A bill enacted in Arkansas in March 2019 allows the Public Service Commission to establish a per-kWh fee to recover quantifiable, direct demand-related distribution costs from net metering customers, while a bill enacted in Virginia allows electric cooperatives to adopt demand charges for net metering customers. A bill pending in Iowa would establish four alternatives to the state's current net metering policy, one of which includes a minimum bill and one including a demand charge.

On the other hand, bills pending in Kansas and Texas prohibit additional charges for DG customers. A bill introduced in Kentucky that did not advance during the 2019 legislative session would have limited the types of costs that may be recovered through fixed charges. A South Carolina bill, as it was originally introduced, would have prohibited additional fees for DG customers and limited the types of cost to be recovered through fixed charges; however, the bill was amended before it was passed by the State House. As amended, the bill calls for the Public Service Commission to consider the cost of service implications of customer-generators on other customers within the same rate class.

Box 6. Demand Charges, Standby Charges, & Grid Access Fees

A **demand charge** is a charge that varies based on a customer's maximum rate of energy consumption, or demand, during a billing period. A customer's demand is measured in kilowatts (kW), and is typically calculated based on the average rate of energy consumption over a 15, 30, or 60 minute interval. The charge is then based on the interval with the highest average demand. In certain cases, only a customer's highest demand during the utility's system peak periods is used in calculating a demand charge, also known as "**coincident peak demand**." Most often, demand charges are based on a customer's "**non-coincident peak demand**", which may occur at any time during the billing period, regardless of when they utility's system peak occurs. Demand charges are common for commercial and industrial customers, and though rare for residential customers, are most often paired with time-of-use rate schedules when included in residential rates. A **standby charge** is a charge applied to customers with on-site generation, and may have volumetric, demand-based, and capacity-based components. Standby charges are intended to compensate the utility for securing access to ample resources so that it can provide power as needed when the customer's on-site generator is not producing energy. Another type of solar charge is a **flat monthly fee**, sometimes called a **grid access charge**, which functions as a higher total fixed charge.

Table 10. Updates on Residential Demand and Solar Charges (Q1 2019)

State	Utility	Monthly Demand/Solar Charge(s)			Description	Source
		Current	Proposed	Approved		
AL	Alabama Power	$5.00 per kW DG capacity	N/A	*Pending*	In April 2018, the Southern Environmental Law Center (on behalf of two individuals and a non-profit organization) filed a formal complaint and petition for a declaratory ruling regarding the legality of Alabama Power's Capacity Reservation Charge included in Rider RGB. Both exporting and non-exporting on-site solar generation facilities are currently required to pay the Capacity Reservation Charge. Alabama Power filed a motion to dismiss the complaint in June 2018. The petitioners filed an amended complaint in July, incorporating their challenge to Alabama Power's recently proposed changes to Rider RGB. In August, the Commission ordered that Alabama Power's motion to dismiss be held in abeyance and that testimony be submitted within 60 days. The Southern Environmental Law Center filed a motion for hearing in December 2018, and Alabama Power argued against holding a hearing in January 2019.	Docket No. 32767
	Alabama Power	$5.00 per kW DG capacity	$5.42 per kW DG capacity	*Pending*	In June 2018, Alabama Power proposed modifications to its Rider RGB. The modifications and charge in its current form are being challenged in Docket No. 32767. Parties filed testimony during Q4 2018. The Southern Environmental Law Center filed a motion for hearing in December	Docket No. U-4226

					2018, and Alabama Power argued against holding a hearing in January 2019.	
AZ	Salt River Project	$13.70	$17.60	$17.60	In December 2018, Salt River Project proposed changes to its Customer Generation tariff (E-27). Among the proposed changes is an increase in the monthly fixed charge for customer-generators from $13.70 to $17.60. The Board approved the changes in March 2019.	SRP Proposed Solar Options Detailed Changes
	Salt River Project	$3.55 - $34.19 per kW, varying by season and level of demand	$3.49 - $33.59 per kW, varying by season and level of demand	$3.49 - $33.59 per kW, varying by season and level of demand	In December 2018, Salt River Project proposed changes to its Customer Generation tariff (E-27). Among the proposed changes is a slight reduction in most of the tariff's demand charges. The Board approved the changes in March 2019.	SRP Proposed Solar Options Detailed Changes
	Salt River Project	$3.55 - $34.19 per kW, varying by season and level of demand	$8.13 - $21.94 per kW, based on the average on-peak daily demand, varying by season	$8.13 - $21.94 per kW, based on the average on-peak daily demand, varying by season	In December 2018, Salt River Project proposed two new tariff options for customer-generators. One proposed option (E-15 Customer Generation Average Demand) features demand charges based on a customer's average daily demand during on-peak hours, rather than maximum monthly on-peak demand. The Board approved the changes in March 2019.	SRP Proposed Solar Options Detailed Changes
CA	Sacra-mento Municipal Utility District	$0.00	$8.00 per kW DG capacity, increasing to $11 per kW by 2025	*Pending*	SMUD's 2019 Chief Executive Officer & General Manager's Report and Recommendations on Rates and Services, published in March 2019, includes a proposal to establish a Grid Access Charge. The charge would apply to customers who place on-site generation into service after April 1,	SMUD Website

					2019. Existing systems will be grandfathered for a period of 10 to 20 years from the original billing period after installation. The Grid Access Charge would be $8 per kW of installed capacity per month in 2020 and 2021, $9 per kW in 2022, $10 per kW in 2023 and 2024, and $11 per kW in 2025. Public workshops on the proposal are scheduled for April and May 2019, and a public hearing is scheduled for June. A revised report was published on April 22, 2019, which withdraws the proposed Grid Access Charge.	
KS	Westar Energy	$0.00	$9.45 per kW during summer months and $3.15 during winter months, based on the 60-min. max demand during peak hours	$9.00 per kW during summer months and $3.00 during winter months, based on the 60-min. max demand during peak hours *Appealed*	In February 2018, Westar Energy proposed implementing a monthly demand charge for residential customers with DG systems. Residential DG customers are currently treated as a separate customer class by Westar, but there are currently no differences in the rates between residential DG and non-DG classes. Residential customers without DG would have the option of opting into a tariff with the same demand charge. Westar also proposed an energy charge that would be higher for DG customers than non-DG customers on the optional demand tariff (7.23 cents per kWh for DG customers versus 5.62 cents per kWh for non-DG customers). The demand charge would be based on the highest 60-minute demand during the billing period, limited to the hours of 2pm to 7pm on non-holiday weekdays. In July 2018, a non-	Docket No. 18-WSEE-328-RTS Order

					unanimous settlement agreement was filed (with several environmental and solar parties not joining the agreement), which included the charges for DG customers. In September 2018, the Commission issued an order approving the agreement. A petition for reconsideration filed by the Sierra Club and Vote Solar in October 2018 was denied in November 2018; those parties filed a petition for judicial review in December 2018. The proceeding remains open.	
MA	National Grid	$0.00	$4.20	*Pending*	As part of National Grid's general rate case, filed in November 2018, the utility proposed a Monthly Minimum Reliability Contribution (MMRC) for net metering customers. The MMRC is in the form of a fixed charge for all applicable rate classes. The proposed MMRCs are as follows: residential - $4.20, small general service - $9.50, general service demand - $28.00, and general service TOU - $164.00.	Docket No. 18-150
MI	DTE Electric	$0.00	$2.31 per kW installed DG capacity	*Pending*	In July 2018, as part of a general rate case, DTE Electric proposed a system access charge for new DG customers. This monthly charge would be based on the capacity of the customer's DG system. The charge would not be applied to DG customers taking service under demand-based rates. A proposal for decision filed in March 2019 would reject DTE's proposed system access charge.	Docket No. U-20162 Proposal for Decision

	Upper Peninsula Power Company (UPPCO)	$0.00	Not Specified	*Pending*	In September 2018, as part of a general rate case, UPPCO proposed a system access contribution for new DG customers. The amount of this charge is not specified in the initial rate case filings (listed as $XX.XX per kW). The system access contribution would not apply to customers taking service under demand-based rates. In February 2019, the Commission Staff recommended deleting the system access charge language, as a value was never specified. In early April 2019, parties indicated that they are close to reaching a settlement agreement.	Docket No. U-20276
MT	North-Western Energy	$0.00	$8.64 per kW, based on the 60-min. max demand during the billing cycle	*Pending*	In September 2018, as part of its general rate case application, NorthWestern Energy proposed the creation of a new customer class for future residential net-metered customers. The proposed residential net metering customer rate includes a mandatory demand charge, based on the customer's non-coincident peak demand.	Docket No. D2018.2.12
NM	Southwestern Public Service Company d/b/a Xcel Energy	$0.0367 per kWh prod-uced	$0.0409 per kWh produced	$0.00 *Appealed*	In October 2017, Southwestern Public Service Company (SPS) proposed an increase in its residential DG production standby charge from approximately $0.005 to $0.006 and an increase in its residential DG transmission and distribution standby charge from approximately $0.031 to $0.035. The standby rates are based on the amount of per kWh production from the customer generation	Docket No. 17-00255-UT Recomm-ended Decision Final Order

					system that is either used on-site or applied as an offset to energy delivered from SPS. A recommended decision was published in late June, which would eliminate entirely the DG standby charge. In a September 2018 order, the Commission accepted the Hearing Officer's recommended decision on the standby charge, canceling the charge (Rate No. 59 and 67) and noted that it will open a rulemaking to address issues around standby charges for DG customers. SPS appealed the decision in September 2018, including the decision to cancel the standby charge, and the Commission denied the petition. SPS then filed an appeal with the Supreme Court of New Mexico. In February 2019, SPS and the Commission filed a joint motion for remand and stipulated dismissal of the utility's appeal, which keeps the standby charge issue before the Court. Vote Solar filed a brief in February, which favors the ultimate determination in the case, but not the reasoning used to reach this determination, where the organization argues that the Commission is still using a "flawed statutory interpretation."	
VT	Green Mountain Power	$0.00	$75 per kW installed DG capacity	*Pending*	In February 2019, Green Mountain Power filed a revised net metering tariff, which includes an additional fee of $75 per kW of installed AC capacity for customers applying for net metering on March 25, 2019 and after. The charge	Docket No. 19-0441-TF

					only applies to net metering systems connecting to circuits identified by Green Mountain Power that have had transmission ground-fault overvoltage upgrades completed after March 25, 2019 or require transmission ground-fault overvoltage upgrades. The fee will apply to other generation projects that are not net-metered as well. Green Mountain Power will identify the affected circuits with a dynamic, color-coded map. The Commission issued an order in March 2019, suspending the tariff filing and opening an investigation. The Commission held a prehearing conference on March 28, 2019.

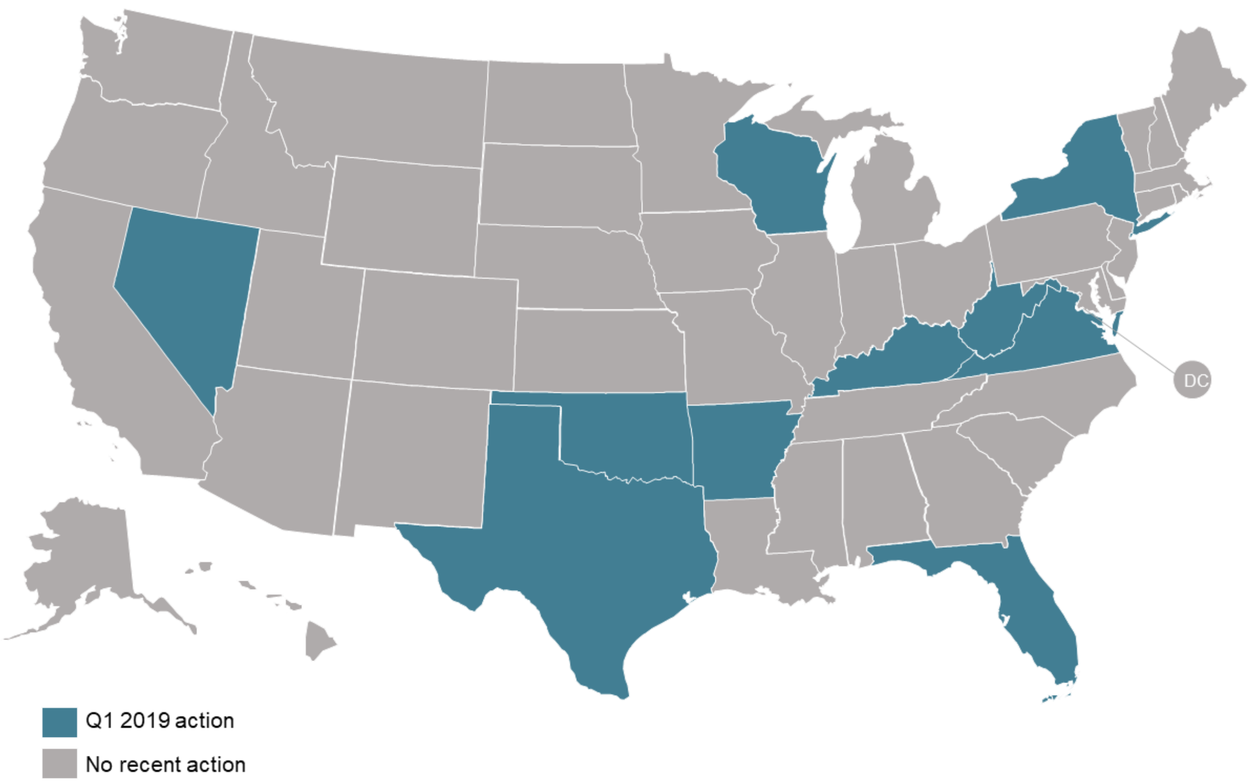
THIRD-PARTY SOLAR OWNERSHIP

Key Takeaways:

- In Q1 2019, 10 states took action regarding the legality of third-party solar ownership options.
- Arkansas lawmakers enacted legislation legalizing solar leasing, and the Virginia General Assembly enacted a bill authorizing third-party PPAs for tax-exempt customers of electric cooperatives.
- Florida regulators issued declaratory statements that residential solar equipment leases offered by Tesla and IGS Solar are allowed, while the Wisconsin Public Service Commission declined to address a petition seeking a ruling on the legality of solar leasing.

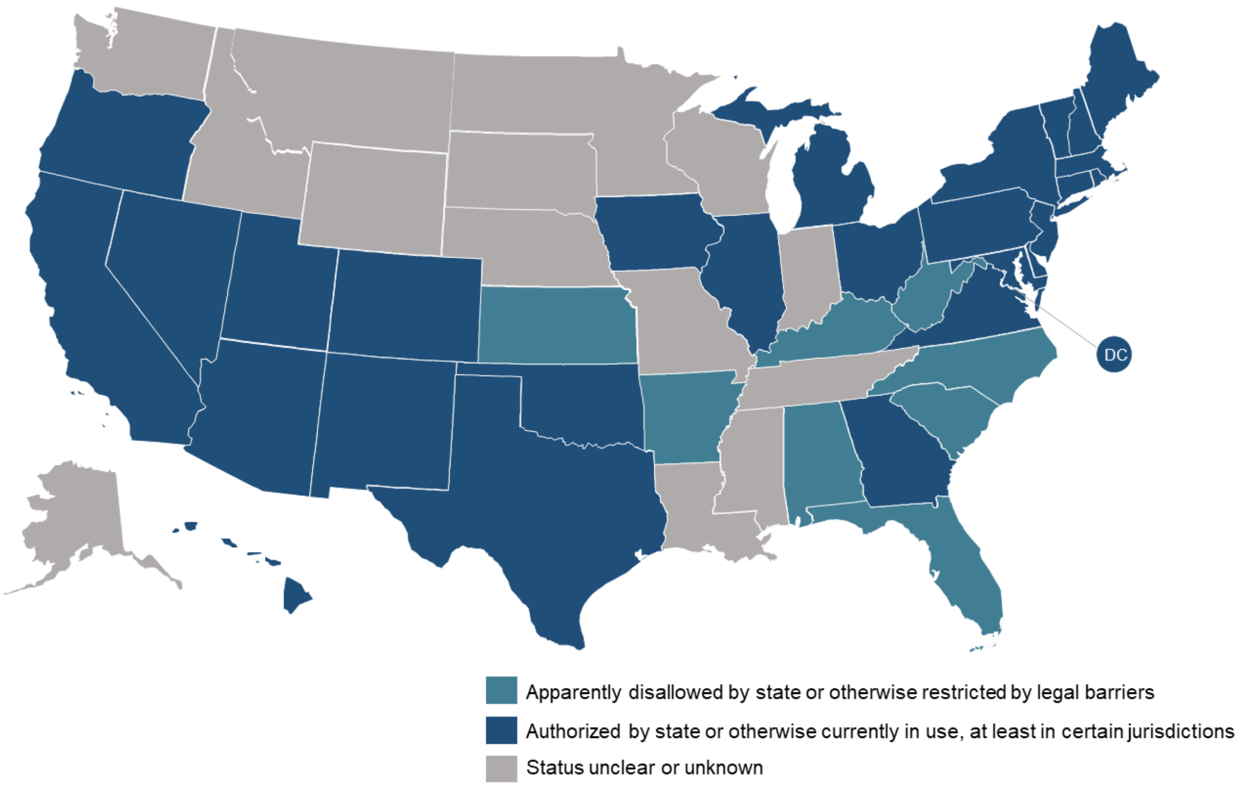
Policymakers and regulators in 10 states considered the legality of third-party solar ownership options in Q1 2019. The majority of actions on this issue taking place this quarter were legislative, with 14 bills under consideration in nine states.

Figure 13. Action on Solar Third-Party Ownership (Q1 2019)



Two state legislature enacted bills in Q1 2019, with an Arkansas bill legalizing solar leasing and a Virginia bill authorizing third-party power purchase agreements (PPAs) for tax-exempt entities that are customers of electric cooperatives. Another Virginia bill considered during the quarter would expand an existing third-party PPA pilot program to include Kentucky Utilities. Lawmakers in several other states, including Florida, Nevada, New York, Oklahoma, and West Virginia considered bills that enable solar leases or third-party PPAs for at least certain customers.

Figure 14. Third-Party Solar PPA Legality (April 2019)



Florida regulators issued declaratory statements during Q1 2019 that allow residential solar leases offered by Tesla and IGS Solar, with accompanying language noting that further declaratory statements are unnecessary for other similar cases. These approvals came after solar lease approvals for Sunrun and Vivint last year. Wisconsin regulators, on the other hand, declined to address a similar request for declaratory judgment from Sunrun, stating that the issue was better left to the state legislature.

Table 11. Solar Third-Party Ownership Updates (Q1 2019)

State	Description	Eligible Sector(s)	Source
AR	S.B. 145 adds customers leasing net metering facilities and entering into contracts with third-parties to operate net metering facilities to the definition of net metering customer, legalizing solar leasing in the state. The bill states that solar lessors will not be considered public utilities. The bill also allows tax-exempt entities to enter into a service contract for electric energy from a net metering facility. These service providers will also not be considered public utilities. The Governor signed the bill in March 2019.	All / Tax-Exempt Entities	S.B. 145 (E)
FL	In December 2018, Tesla filed a petition for a declaratory statement that its residential solar equipment lease does not constitute a sale of electricity, does not deem the company a public utility, and does not subject the company or its customer-lessees to Commission regulation. The petition follows similar petitions from Sunrun and Vivint, which were approved. In January 2019, the Commission Staff recommended that the Commission grant Tesla's petition and declare that Tesla's residential solar equipment lease does not constitute a sale of electricity, deem the company a public utility, or subject the company to Commission regulation. The Public Service Commission approved Tesla's petition in February 2019. The order notes that petitions with identical fact patterns to Sunrun's, Vivint's, and Tesla's petitions, these declaratory statements have precedential significance and individual declaratory statements are not necessary.	Residential	Docket No. 20180221
	In February 2019, IGS Solar, Inc. filed a petition for a declaratory statement that its residential solar equipment lease does not constitute a sale of electricity, does not deem the company a public utility, does not subject the company or its customer-lessees to Commission regulation, and that its customer-lessees will be entitled to interconnection as net metering customers. The Commission Staff filed its recommendation in late March 2019, recommending that the petition be granted, declaring that the company's residential solar equipment lease does not constitute a sale of electricity, does not deem the company a public utility, does not subject customer-lessees to regulation, and allows customer-lessees to net meter.	Residential	Docket No. 20190040
	S.B. 222 exempts from the definition of a public utility renewable energy systems up to 2.5 MW that are owned and operated by a property owner who produces, provides, or sells energy from the system to users located on the property.	Multi-Unit Buildings	S.B. 222 (I)

KY	H.B. 146 amends the definitions of "utility" and "retail electric supplier" to exclude third-party power purchase agreements (PPAs) from regulation as a utility. The bill gives the Public Service Commission the responsibility to approve and deny PPAs and require it to deny PPAs that result in rate increases for the retail electric supplier. The bill did not advance during the 2019 legislative session.	All	H.B. 146 (D)
	An amendment to S.B. 100 would have legalized solar leases and allowed leased solar installations to qualify for net metering. This amendment was not included in the final version of the bill.	All	S.B. 100 (Relevant Provisions Amended Out)
NV	S.B. 167 modifies the laws related to third-party sales of electricity by removing the 150% of demand limitation on system size, and allowing a single system to serve multiple dwellings on one property.	Residential	Docket No. 18-10008
NY	S.B. 3579 redefines "customer-generator" so as to include customers who lease generation equipment.	All	S.B. 3579 (I)
OK	H.B. 2184 changes the definition of a public utility in Oklahoma to exclude solar leasing companies in unincorporated areas and in incorporated areas when they meet Public Utility Regulatory Policies Act requirements.	All	H.B. 2184 (I)
	S.B. 525 prevents the Corporation Commission from prohibiting third-party leasing arrangements for small power production facilities.	All	S.B. 525 (I)
TX	H.B. 2860 and S.B. 2066 entitle DG customers to timely interconnection, prohibit utilities from charging additional fees to DG customers beyond the additional cost necessary to interconnect their system, and establish consumer protections for third-party leases and power purchase agreements.	All	H.B. 2860 (I) S.B. 2066 (I)
VA	H.B. 1252 expands the state's current third-party power purchase agreement pilot program to include Kentucky Utilities as well. The bill also increases the maximum eligible system size limit for pilot program participation for non-residential customers from 500 kW to 1 MW. The bill passed the House in February 2018, and the Senate voted to carry it over into the 2019 session. The bill did not advance during 2019.	Tax-Exempt Entities / Schools	H.B. 1252 (D)
	S.B. 1769 authorizes 3rd party PPAs for tax-exempt customers of electric cooperatives. The Senate passed the bill and sent it to the House on February 1, 2019.	Tax-Exempt Entities	S.B. 1769 (E)
WI	In early December 2018, Sunrun filed a petition for a declaratory ruling that its residential solar equipment	Residential	Docket No. 9300-DR-103

	lease will not cause the company to be deemed a public utility under Wisconsin law. Several parties filed comments regarding the petition in late December 2018; the Environmental Law and Policy Center supported the petition while Fair Rates for Wisconsin's Dairyland and the Wisconsin Utilities Association opposed the petition. The Wisconsin Public Service Commission issued an order declining to open a docket in early February 2019, stating that the issue was better left to the legislature.		
WV	H.B. 2911 and S.B. 409 authorize third-party PPAs and leases by specifying that providers of such services are not considered public utilities.	All	H.B. 2911 (I) S.B. 409 (I)
	H.B. 3072 authorizes third-party PPAs as of January 1, 2020 and requires the Public Service Commission to adopt rules to serve as guidelines.	All	H.B. 3072 (I)

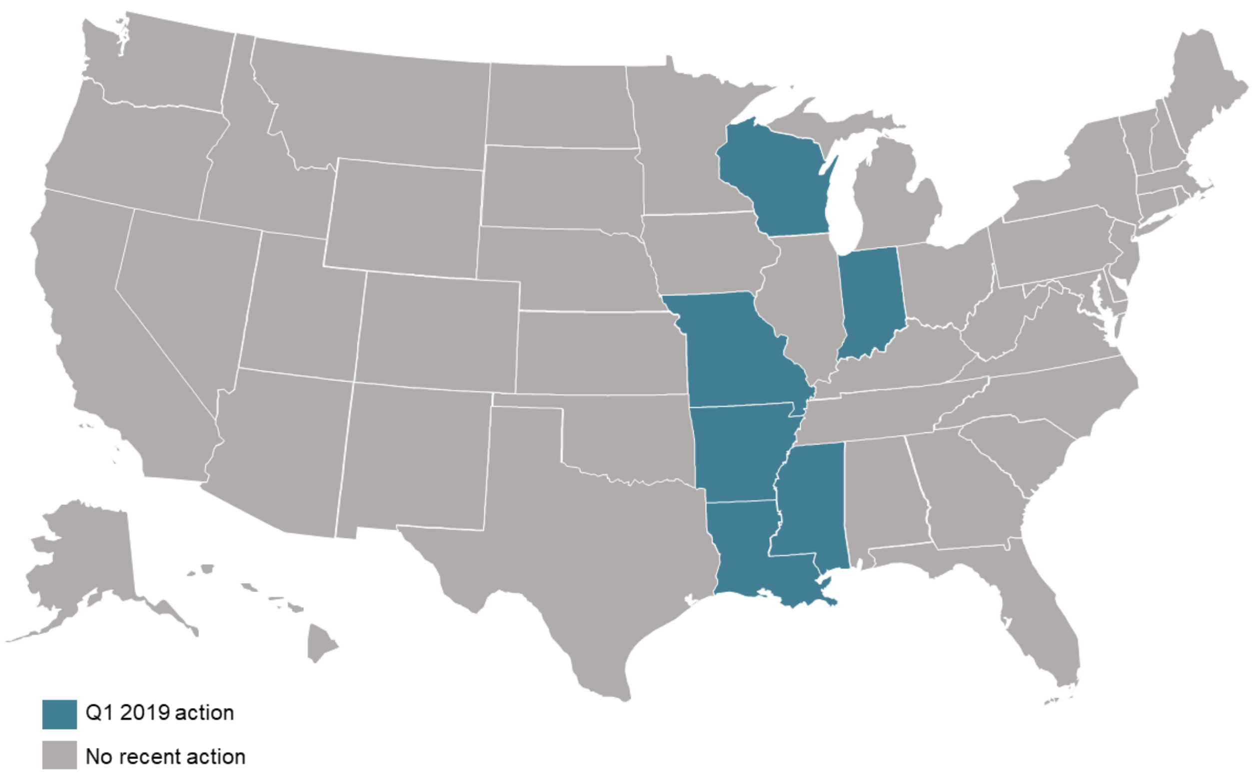
UTILITY-LED ROOFTOP SOLAR PROGRAMS

Key Takeaways:

- Six states took actions related to utility-led rooftop solar programs during Q1 2019.
- Wisconsin Power & Light filed an application for a customer-hosted renewable energy program.
- Entergy New Orleans launched its pilot Residential Rooftop Solar Program.

Utilities are continuing to show an interest in ownership of roof-mounted solar systems. Entergy New Orleans officially launched its Residential Rooftop Solar Pilot Program in Q1 2019. The program is targeting low-income customers and will provide them with a $30 monthly bill credit in exchange for hosting a utility-owned system on their roof.

Figure 15: Utility-Led Rooftop Solar Program Updates (Q1 2019)



Wisconsin Power & Light became the latest utility to file an application for a customer-hosted renewables program in February 2019. Under the proposed program, the utility would provide a leasing payment to customers who host a utility-owned solar system and/or a battery storage system with a capacity between 200 kW and 2.25 MW. The leasing payment is based on the MISO accredited capacity value of the system. The pilot program is capped at 35 MW, with 10 MW reserved for non-profit organizations.

Table 12. Updates on Utility-Led Rooftop Solar Programs and Policies (Q1 2019)

State	Utility	Description	Source
AR	All Utilities	In April 2016, the Public Service Commission (PSC) opened a general proceeding regarding DERs. In November 2017, the PSC issued an order outlining specific topics and questions to address during this proceeding, including many related to advanced metering infrastructure (AMI) deployment, pursuant to the final order in Entergy Arkansas' AMI deployment proceeding. These issues include identification of non-quantifiable functionalities and DERs that can be enabled or enhanced by AMI, and which of these are better offered by utilities or third parties. As part of this, parties are to consider competitive concerns related to utility offerings and potential remedies. The PSC issued an order in July 2018 with an initial list of issues to be considered during the proceeding. These issues include the appropriate roles for distribution utilities, third-party DER providers, and customers; tariff-based DER programs; net metering and rate design; and DER compensation and program design for low-income participation among many other specific DER and grid modernization issues. Comments on the proposed issues were accepted until late September 2018, and the Commission intends to schedule an initial educational workshop on procedural issues.	Docket No. 16-028-U Order No. 10
IN	Duke Energy Indiana	In September 2018, Duke Energy Indiana filed a petition for approval of a new solar services program tariff which would provide an alternative means for financing solar installations located on a non-residential customer's property. Customers would pay a monthly fee to cover the cost of construction, operation, and maintenance of the solar installation. The total capacity to be installed under this program would not exceed 12 MW. Customers would receive all electricity generated by the installations and would be credited through net metering; however, capacity installed under this program would not count towards the aggregate net metering capacity limit for Duke Energy Indiana. An evidentiary hearing was held in late January 2019. Duke Energy filed a proposed order in February 2019, justifying approval of the program. Multiple parties filed exceptions to the proposed order in late February 2019, and Duke Energy filed a reply brief in March 2019.	Docket No. 45145
LA	Entergy New Orleans	On February 28, 2019, Entergy New Orleans announced the launch of its pilot Residential Rooftop Solar Program, where the utility installs solar systems on low-income customer rooftops. Participating customers receive a $30 monthly bill credit and may choose to have the system removed at any point with a 90-day notice.	Press Release
MO	Ameren	In December 2016, the Missouri Public Service Commission issued an order approving a solar partnership pilot program proposed by Ameren Missouri, which would have consisted of up to $10 million in investment in solar facilities by Ameren Missouri, with the facilities to be located on the property of Ameren customers. The Office of the Public Counsel appealed	Docket No. 2016-0208

		the order, and the appeal was resolved with an agreement on a smaller pilot program, with up to $4 million in investment and only one facility. In November 2018, Ameren submitted its proposed site for the facility: a parking garage owned by BJC Healthcare and Washington University in St. Louis. The Commission Staff submitted a report finding the site met all requirements of the agreement in January 2019.	
MS	Entergy Mississippi	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 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.	Docket No. 2018-UN-133
WI	Wisconsin Power & Light	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 community solar program would be based on utility-owned solar installations totaling 3 MW of capacity; subscriptions could not exceed 100% of a subscriber's average annual electricity usage and could be for no more than 60% of the capacity of any one solar facility (each facility is anticipated to be around 1 MW). Subscribers would be charged an upfront fee. The partner program would allow customers to make contracts with designated renewable generators and receive bill credits based on MISO prices. 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).	Docket No. 6680-TE-104

Q2 2019 OUTLOOK

Most state legislative sessions will continue into Q2 2019, with over 130 bills related to net metering, rate design, and solar ownership still under consideration across the country. One state – **Louisiana** – began its legislative session in April 2019.

Four bills making changes to net metering in **New Hampshire** have currently passed one chamber and remain pending, while a bill initiating the development of a net metering successor tariff has passed the **South Carolina** State House.

A bill increasing the net metering aggregate cap is pending in **Washington**, while a bill making significant changes to net metering in **Iowa** has stalled after passing the Senate. Bills adopting new community solar programs are under consideration in **Florida**, **Nevada**, **Pennsylvania**, and **South Carolina**.

Sixteen bills related to community solar remain under consideration in **Minnesota**, while a bill increasing the system size limit for community solar gardens has currently passed the **Colorado** State House.

In early April 2019, **Idaho** Power filed an application to suspend its commercial and industrial net metering tariff and initiate a process to consider modifications. Meanwhile, the **Maine** Public Utilities Commission opened an emergency rulemaking to revise net metering rules in accordance with L.D. 91.

The Rate Design working group within the **District of Columbia**'s MEDSIS proceeding recommended undertaking a value of DER study, and net metering is among the issues that **Arizona** regulators continue to consider in an expansive rulemaking proceeding.

A proposed decision remains under consideration in DTE Electric's **Michigan** rate case, and a final decision is expected during Q2 2019. Parties are continuing settlement negotiations in Upper Peninsula Power Company's rate case.

Several general rate cases are expected to be filed in Q2 2019. Tucson Electric Power in **Arizona** and CenterPoint Energy in **Texas** filed rate cases in early April 2019, and Eversource and Liberty Utilities in **New Hampshire** have indicated that they intend to file rate cases in April as well.

El Paso Electric in **New Mexico** requested an extension of time until the end of July 2019 to file its next rate case. Twenty-five requests to increase residential fixed charges or minimum bills were pending at the end of Q1 2019.

ENDNOTES

[1] Austin Perea, Colin Smith, Michelle Davis, Allison Mond, Benjamin Gallagher, Cory Honeyman, Shawn Rumery, Aaron Holm, Rachel Goldstein, & Justin Baca, *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[2] Perea, et al., *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[3] Perea, et al., *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[4] Perea, et al., *U.S. Solar Market Insight Q4 2018 Executive Summary,* Wood Mackenzie & Solar Energy Industries Association (SEIA), December 2018, https://www.seia.org/us-solar-market-insight.

[5] J. Coughlin, J. Grove, L. Irvine, J. F. Jacobs, S. J. Phillips, L. Moynihan, and J. Wiedman, *A Guide to Community Solar: Utility, Private, and Non-Profit Project Development*, National Renewable Energy Laboratory, 2010, http://www.nrel.gov/docs/fy11osti/49930.pdf.

[6] Daisy Chung, Brenda Chew, Medha Surampudy, and Maclean Keller, *2018 Solar Market Snapshot*, Smart Electric Power Alliance, July 2018, https://sepapower.org/resource/2018-utility-solar-market-snapshot/.