Advanced Energy Perspectives
Top 10 Utility Regulation Trends of 2019 – So Far
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In January, we published a list of the top 10 utility regulation trends of 2018. With 2019 at around the halfway point, we check in on the top public utility commission (PUC) actions and trends so far this year. Ten prominent trends and actions stand out above the rest, from renewables increasingly dominating utility resource plans, to wildfires sparking utility safety and liability concerns in California, to transportation electrification investments becoming more widespread from coast to coast. Here is the full round-up of the top 10 matters before PUCs so far in 2019.

Note: some links in this post reference PUC filings and other documents in AEE's software platform, PowerSuite. Click here and sign up for a free trial.

1. Renewables Dominating Utility Resource Plans

During the first six months of 2019, the trend in recent years has continued toward a more advanced, clean, and flexible grid. This has largely been driven by the continued price decline in renewables. In most states, it is now often cheaper to build new wind and solar plants (in some cases even when paired with storage) than to operate existing fossil-fuel power plants. Utilities are starting to take notice, and renewables are dominating their long-term resource plans. As you can see in the map below, at least nine states plus Puerto Rico and D.C., have now set 100% clean energy targets. (For a discussion of this trend and its implications for utilities, regulators, and renewable energy developers, see AEE's recent webinar, "What Happens When Wind and Solar Win on Price?").

To kick off 2019, the **New Mexico** Public Regulation Commission approved Public Service Co. of New Mexico's (PNM) latest integrated resource plan (IRP), which calls for the retirement of all coal-fired generation in its portfolio by 2031.

In **Michigan**, DTE Electric Co. and Consumers Energy Co. both recently proposed plans to phase out coal by 2040. In March, DTE proposed 11 MW of solar-plus-storage projects and 693 MW of wind projects over the next five years, followed by 525 MW of solar between 2025 and 2030 and another 2 GW by 2040. In June, the Public Service Commission approved Consumers' plan, which calls for 5 GW of new solar by 2030 and a 90% reduction in carbon emissions by 2040.

In April, Public Service Co. of **Colorado** received approval for the construction of a $743 million, 500 MW wind farm (representing about 8% of its peak summer demand), which the utility aims to bring into commercial operation by the end of 2020, to take advantage of the full value of the federal production tax credit. This represents only a small piece of the power company's expected energy transition over the next couple decades, with the goal of achieving 100% carbon neutral generation by 2050.

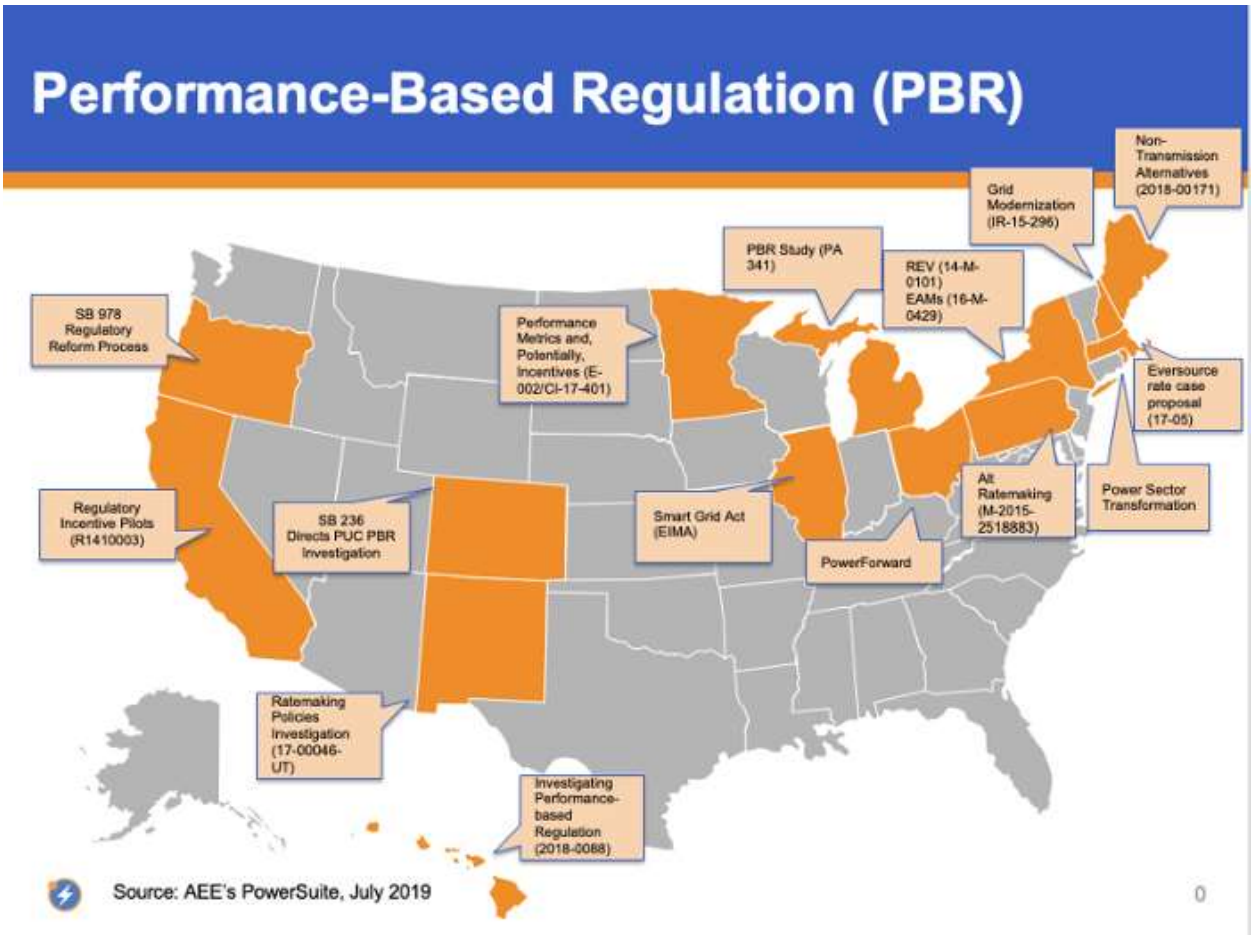
In April, Northern **Indiana** Public Service Co (NIPSCO) filed a petition for a $21 million annual electric revenue increase, that is premised on its most recent integrated resource plan which proposes to retire all coal in its fleet by 2028 and replace it with a portfolio of solar, storage, wind and demand management. NIPSCO stated its plan is expected to save customers $4 billion over the next 30 years.

In June, **Georgia** Power reached a settlement agreement in its 2019 Integrated Resource Plan that calls for the retirement of close to 1 GW of coal generating capacity and the procurement of 1.5 GW of renewable resources and 150 MW of distributed generation resources. This plan marks the continued steep decline in Georgia Power's emissions in recent years driven by plant economics, as these planned retirements are in addition to 3.1 GW of already retired coal plants — representing about 20% of its existing peak load.

Even **Mississippi**, which historically has not been a hot bed for renewables, is joining the party. At the beginning of the year, Entergy Mississippi filed an application for a $138 million, 100 MW solar facility. Entergy said they are pursuing the solar facility because of increasing customer interest and the recent reductions in solar costs. If approved, it would be the first large-scale, utility-owned solar project constructed in Mississippi.

2. Re-thinking the Utility Business Model

Many states are exploring changes to the traditional cost-of-service regulatory model to move toward a system that better reflects new market conditions, allows utilities to take advantage of the growing service economy, and rewards performance against established goals rather than inputs. For more information, take a look at the Navigating Utility Business Model Reform paper and series of case studies AEE Institute released in November, in collaboration with Rocky Mountain Institute and America's Power Plan. The case studies highlight utility business model reforms being implemented in the U.S and abroad while the paper lays out a menu of business model reform options and practical guidance for pursuing reform at the state level.



In January, the **Minnesota** Public Utilities Commission (PUC) finalized Phase 1 in its performance based regulation (PBR) investigation for the state's largest utility — Xcel Energy. The Commission kicked off Phase 2 in March, which commenced a stakeholder process to create a set of metrics for the five performance outcomes established in Phase 1 – affordability, reliability, customer service quality, environmental performance, and cost-effectively aligning generation to load.

In January, **New York**'s Con Edison filed a petition to increase its annual electric and gas delivery revenues. A key component of the rate case is the implementation of earnings adjustment mechanisms (EAMs) -- New York's version of performance incentive mechanisms -- coming out of the Reforming the Energy Vision (REV) initiative.

The Public Utilities Commission of **Hawaii** (PUC) concluded Phase 1 and set the groundwork for Phase 2 in its proceeding to develop a new PBR framework for the Hawaiian Electric Companies. In May, the PUC issued a Phase 1 decision which identified 12 key outcomes and a portfolio of priority PBR mechanisms for updating Hawaii's regulatory design. The Decision established the guiding principles and objectives for Phase 2 to include: (1) setting a revenue target to optimize near-term customer savings; (2) enhancing customer engagement; (3) improving DER performance; (4) streamlining utility performance; and (5) re-aligning financial incentives with societal outcomes (e.g., GHG reductions, transportation electrification, resilience). Phase 2 will formally begin in August and focus on revenue adjustment mechanisms and performance mechanisms as the main track for exploring and developing PBR.

The **Colorado** Public Utilities Commission will also soon be engaged in re-thinking utility regulation with the passage of SB 236 — the PUC Sunset bill signed into law in May. Among other things, the bill requires the PUC to study the impacts of performance-based metrics to better understand and identify mechanisms that would encourage the state's utilities to make investment decisions that benefit the public good, increase energy savings, and improve safety and reliability. The bill also authorizes the creation of a ratepayer-backed bonding mechanism (securitization) to expedite the closure of outmoded power plants as the state transitions to cleaner, more economic resources.

In addition to these efforts to rethink utility business models and regulation on a broad basis, many states have taken on specific aspects of reforming how utilities conduct their planning and operations, such as distribution system planning (see #3) and procuring non-wires alternatives to traditional utility investments (see #4).

3. Distribution System Planning for Distributed Resources

The distribution grid is the backbone of a reliable electric system used to deliver electricity from the transmission system to individual consumers. Modern planning processes are critical for providing essential electric service efficiently and cost-

effectively. As DER deployment continues to grow, utilities and DER companies are seeking ways to maximize the benefits of DERs to the system, while maintaining reliability and reasonable costs for customers. **New York** and **California** have continued to refine their distribution system planning processes in 2019, while several additional states have taken steps to implement processes of their own.

In February, the **New Hampshire** Public Utilities Commission staff issued a report with a recommended approach for utilities to assess their distribution systems, conduct least-cost distribution planning strategies, and incorporate grid modernization initiatives.

In April, **Ohio**'s utilities (AEP Ohio, Duke Energy, and FirstEnergy) filed their grid architecture status reports, as required by the Public Utility Commission of Ohio's PowerForward roadmap, to identify where each utility stands on its path to a modern grid. The reports differ widely from utility to utility. Most notably, FirstEnergy's report is noticeably shorter and less comprehensive than the other utilities' reports. That said, topics in the reports range from a status report on grid architecture (i.e., field

automation, substation automation, operational communications infrastructure, sensing and measurement, operational analytics, and standardized access to customer energy usage data) to an assessment of distribution system planning practices and ability to integrate new technologies.

In addition to the actions mentioned above, a few other states have continued their existing distribution system planning investigations in 2019, including **Hawaii**, **Michigan**, and **Minnesota**.

One of the core outputs of distribution system planning is recognizing opportunities for new advanced technologies and services to meet system needs — which we explore next.

4. Non-Wires Alternatives to Traditional Utility Investments

Non-wires alternatives (NWAs) to traditional investments in transmission and distribution equipment are increasingly being looked to as viable options in several key states. The next steps to making NWAs a widespread reality are to (1) identify the areas where NWAs can meet a need at a lower cost than a traditional utility investment, and (2) develop a framework to implement and/or procure the NWA solution. Several states have made significant progress so far in 2019.

In January 2019, Con Edison in **New York** outlined its plan to continue implementation of its Brooklyn Queens Demand Management (BQDM) program through 2021. The utility plans to continue procurement of additional load reduction above the original 41 MW of non-traditional customer-side electricity demand reduction solutions (projecting 44.5 MW by 2021) and 11 MW of non-traditional utility-side solutions (projecting 18 MW by 2021). For a deep dive on the BQDM program and its success so far, see AEE's case study here.

In June 2018, Central **Maine** Power and Emera Maine filed recommendations that would eliminate their existing incentive to favor transmission and distribution (T&D) investments over NWAs. Specifically, they called for: 1) a revenue decoupling mechanism, 2) a ratemaking approach to treat NWA investments in a similar manner to T&D investments, and 3) an approval process for NWA proposals. As a follow-on to those recommendations, the utilities were ordered to submit supplemental filings in

March outlining how they consider and implement NWAs are part of their T&D investment planning processes. The Commission is now considering those proposals.

In May, the **California** Public Utilities Commission issued a ruling modifying the distribution investment deferral framework process, an annual process (first implemented in 2018) to identify, review, and select opportunities for third party-owned DERs to defer or avoid traditional capital investments. As part of the ruling, the CPUC streamlined the planning process to reduce the time associated with stakeholder participation. The Commission ordered utilities to file their grid needs assessment – identifying the technical and operational planning needs they need to meet five-year load growth forecasts – and a distribution deferral opportunity report – identifying utilities' planned investments and opportunities for third party-owned DERs to avoid or defer those investments by August.

5. Wildfire Liability Challenging California Utilities

In January, the largest investor-owned utility in California — Pacific Gas & Electric (PG&E) — filed for Chapter 11 bankruptcy because of accrued liabilities resulting from the devastating wildfires of 2018. As part of the bankruptcy process, PG&E sought and received approval for $5.5 billion in financing to support operations and ongoing safety initiatives during the bankruptcy process. There are still a lot of unanswered questions that will need to be sorted out through the courts. One of the most important questions for the advanced energy industry will be whether PG&E is granted the ability to renegotiate a portion of their existing $34.5 billion in renewable energy contracts to help pay down their debts. A decision that could encumber California's efforts to meet its clean energy and greenhouse gas reduction goals. Outside of the bankruptcy process, the wildfires kick started wide ranging investigations into wildfire prevention and cost recovery plans, as well as PG&E's safety culture.

At the start of the year, the California Public Utilities Commission opened an investigation to determine if PG&E, as currently constituted, is able to provide safe electric and gas service and to review alternatives to PG&E's current management and operational structures. As a result of that investigation, the Commission established a Commission Advisory Panel of experts to advise the Commission on corporate governance issues to ensure that utilities are prioritizing safety moving forward. More pointedly, the Commission in late June introduced four proposals (which the

Commission is currently seeking comments on) to improve PG&E's safety culture. The four proposed pathways include: (1) separating PG&E into separate gas and electric utilities or selling the gas assets; (2) establishing periodic review of PG&E's Certificate of Convenience and Necessity (CPCN) to operate as a monopoly in California; (3) modifying or eliminating PG&E's holding company structure; and (4) linking PG&E's rate of return or return on equity to safety performance metrics. If adopted, any one of these pathways would have wide-ranging implications.

Also in June, the CPUC adopted a set of criteria and a methodology for conducting a financial "stress test" for future wildfire cost recovery. The methodology is intended to inform determinations of the maximum amount an electric corporation can pay without affecting their ability to raise money in capital markets, which could ultimately harm ratepayers or affect their ability to provide safe and adequate service.

6. Increasing Access to Renewable Energy

As renewable energy has become more competitive on price, customers are increasingly looking for ways to not only power their operations with 100% renewable energy, but also dampen price volatility and reduce energy costs. There are several avenues for customers to increase their access to renewable energy ranging from direct access programs to renewable energy tariffs to community solar programs. (For a discussion of best practices and steps that states and utilities can take to meet large customer demand for renewable energy, see the Advanced Energy Buyers Group's recent report here.)

In January, Xcel Energy in **Minnesota** filed for approval to expand their Renewable*Connect Pilot Program (a renewable energy tariff aimed at businesses that want access to renewable energy) into a full-fledged program. Xcel stated that the pilot sold out in one year and there are more than 400 customers on a waiting list.

In March, the **California** Public Utilities Commission opened a rulemaking to implement SB 237, reopening of the state's direct access (DA) program. The DA program, which has been limited to about 11% of peak load since 2010, allows retail nonresidential customers to purchase electricity service directly from competitive providers. In June, the Commission issued a Phase 1 order to expand the DA cap by 4 TWh or an additional 2% to 3% of peak load allocated proportionally to the investor-owned utilities' service territories. Phase 2, which is expected to begin before the end of the year, will

be focused on the second requirement of SB 237, issuing recommendations to the Legislature on a full expansion of the DA cap to nonresidential customers by June 1, 2020.

In May, Dominion Energy In **Virginia** filed an application for a 100% renewable energy tariff that would allow customers with under 5 MW of peak demand to receive 100% of their energy and capacity from a portfolio of renewable resources owned or procured by Dominion for a premium over standard service.

In March, **Florida** Power & Light (FP&L) proposed a solar subscription program — SolarTogether. The program would give customers of all rate classes the option to subscribe to blocks of solar capacity (with no long-term commitment) from dedicated 74.5 MW solar power plants. FPL stated it has already pre-registered 200 customers, totaling 1,000 MW, for the program, mostly from commercial and industrial customers.

7. Community Choice Aggregation

Community choice aggregation (CCA) or municipal aggregation has been around for a few decades but it has risen in popularity the past couple of years, driven in large part by communities wishing to take control over how their energy is generated. The concept of CCA is fairly simple. CCAs are classified as governmental entities, most often formed by cities and/or counties, that procure power on behalf of their residents. While the CCA provides power for residents, the designated utility still continues to provide transmission and distribution service in the area. In **California,** CPUC staff has estimated that by 2025 over 85% of California's IOU retail load could be served by Community Choice Aggregators and other DA providers (up from about 20% today). On the opposite coast, **New York** recently refined its framework to make it easier to form CCAs, which has led to several municipalities filing implementation plans.

In January, the **Massachusetts** Department of Public Utilities (DPU) opened an investigation into improving the retail electric competitive supply market in Massachusetts, including increasing customer awareness of the competitive market and the value it can provide. In June, the DPU established two working groups which, among other things, will focus on improvements to the Energy Switch website, including but not limited to the display of municipal aggregation products. This is a timely investigation, as in June, the City of Boston petitioned the DPU to approve a community choice aggregation plan to procure power on behalf of its residents. If approved, the

plan would allow the City to solicit the necessary power in October 2019 and start service in January 2020.

8. Strategies to Electrify Transportation

The deployment of electric vehicle (EV) charging infrastructure has risen to the fore in many jurisdictions, as improvements in technology have dramatically expanded the EV market and PUCs have continued to develop focused transportation electrification strategies. (For more information on what utility commissioners need to know about the accelerating EV market, see AEE's EV issue brief.)

California continues to lead on transportation electrification (TE), with 49% of the nation's electric car sales originating in the Golden State. At the turn of the year, the California Public Utilities Commission initiated a rulemaking to provide more structure and guidance on future transportation electrification investments and to streamline the application process. Under California's existing construct, all utility applications have been considered on a case-by-case basis, which has led to a prolonged review process and unfocused investment strategy. This new process, referred to as the DRIVE OIR, seeks to develop a TE framework that will help to strategically integrate TE load; enhance market coordination of utility investments; enable private sector investments; achieve policy cohesiveness on key issues (i.e., rate design, consumer education, and vehicle-grid integration (VGI) policy); and evaluate cost effectiveness of investments and different ownership and cost recovery models. A staff proposal for a TE framework is expected to be issued in October.

In January, the Public Service Commission of **Wisconsin** opened an investigation to consider policies and regulations in regards to EVs and their associated supply infrastructure in Wisconsin. In February, the **Missouri** Public Service Commission opened a proceeding to evaluate potential mechanisms for utility involvement in EV charging stations. The proceeding seeks to evaluate the following three models: (1) utility owned and operated charging stations; (2) a utility "make ready" option; and (3) an alternative incentive program where program parameters, implementation, and cost recovery would be evaluated and defined in a future rate proceeding.

In February, the **New York** Public Service Commission issued an order approving a proposed incentive program to encourage the deployment of public direct current fast charging (DCFC) stations. The consensus proposal – which was jointly filed by the

state's utilities, the New York Power Authority, the Department of Environmental Conservation, the Department of Transportation, the New York State Thruway Authority, and the New York State Energy Research and Development Authority (NYSERDA) – will provide $31.6 million in incentives for over 1,000 publicly accessible DCFC charging stations. Specifically, each utility will offer an annual per-plug incentive that will decline over time as electric vehicle usage, and thus DCFC utilization, increases.

In June, the **Vermont** Public Utility Commission submitted a report to the state legislature recommending the removal of barriers to the adoption of EVs, including more EV purchase incentives, easier pathways for the installation of public charging infrastructure, and increased education and outreach. The **Arizona** Corporation Commission (ACC) has also been in the thick of developing an EV policy implementation plan in 2019 that provides guidelines for utilities to propose EV pilot programs focused on structure, education and outreach, make-ready, rate design, incentives/rebates, and cost recovery.

There has been no shortage of activity across the country with utility proposals or statewide investigations in **Colorado, Delaware**, **Iowa**, **Maryland**, **Michigan (**DTE Electric and Consumers Energy**) Minnesota**, **North Carolina**, **Oregon, South Carolina** (Duke Energy Progress and Duke Energy Carolinas), and **Texas.** For an overview of the benefits of electrifying transportation, with a specific focus on the medium- and heavy-duty vehicle sector, see our recently released industry fact sheet here.

9. Grid Modernization Investments for DER and Large-Scale Renewables

Grid modernization is often used in the electricity industry as a catch-all term for grid investment. However, at AEE, we view grid modernization as comprising the foundational investments needed to enable a reliable and flexible grid. Such a modern grid platform is essential to fully integrating DER, balancing increasing levels of large-scale renewables and enhancing the customer experience.

The first step toward grid modernization is often advanced metering infrastructure. In May, Indiana Michigan Power took this first step by filing an application in **Indiana** as part of a larger general rate case asking for full smart meter deployment by 2022.

Other states are looking at grid modernization more holistically. In March, the **Arkansas** Public Service Commission kicked off a long-awaited DER and grid modernization investigation. The first phase of the investigation will inform stakeholders on the existing state of the grid, including aging distribution infrastructure, the role of data in a modern grid, and the impact of DER on utility planning and operation.

Meanwhile in the **District of Columbia,** six working groups with over 100 participants across industry, government, consulting, and advocacy groups met from August 2018 to May 2019, working through a variety of issues facing its electric power system. The collaborative process focused on identifying technologies and policies that can modernize its energy delivery system for increased sustainability and make it more reliable, efficient, cost-effective and interactive. In May, the process culminated in a final stakeholder report with 32 recommendations (i.e., more fundamental reforms that require further discussion) for consideration by the PSC related to data and information access and alignment, non-wire alternatives, rate design, utility business model reform, customer impacts, microgrids, and pilot projects.

10. Net Metering and Valuing DER

Net energy metering (NEM) has been successful in spurring the adoption of distributed generation across the country. As net metering-eligible resources continue to decline in price, the number of NEM customers has increased, which has led to pushback in many jurisdictions. Over the past couple of years, states have taken various approaches to successor tariffs to NEM, ranging from reductions in net metering rates for exported electricity to the development of regulatory structures to more precisely value and source services from DER (see #10, of last year's Top 10).

This year, one example of the holistic approach to NEM reconsideration can be found in **Connecticut**, where in June the Department of Energy and Environmental Protection (DEEP) and the Public Utilities Regulatory Authority (PURA) opened a proceeding to study the value of DER as required by Public Act 19-35. DEEP and PURA are required to submit a report on their findings to the General Assembly by July 2020.

Other states, however, seem to be moving in a direction that is not favorable to future DER adoption. In January, the **Louisiana** Public Service Commission Staff proposed a rule that would compensate new net metering customers at avoided cost, rather than the retail rate, though also promising payment for any quantifiable locational, capacity-

related, or environmental benefits. In April, **Idaho** Power filed a petition to suspend net metering service and explore modifications to the compensation structure under its net metering program, affecting customer-owned generation facilities with capacity up to 100 kW, even though existing net metered capacity represents just 0.15% of the utility's summer peak demand of 3,400 MW. Idaho Power expressed concern that capacity under its net metering tariff had increased 114% in the first quarter of 2019 alone, driven by large commercial, industrial, and irrigation customers, with capacity from the irrigation class jumping from 1.09 MW to 5.06 MW. No decision has been made to date, but if the Public Utilities Commission sides with the utility, it could nip Idaho distributed generation in the bud.

On a more positive note, **New York** recently made some landmark adjustments that should provide fairer treatment for customers that have significant distributed generation facilities. In April, the Commission issued an order that made revisions to the state's DER value calculation and compensation methodology, and also adopted a new credit to encourage community distributed generation development. And in May, the Commission issued an order modifying the current standby and buyback service rates that will improve the alignment between system costs and how DER customers make use of the grid, which should ultimately improve the prospects for DER deployment. (For a more detailed look at this order, read more here.)