K&L GATES

ENERGY STORAGE HANDBOOK

NOVEMBER 2020 **VOLUME 6**

NEW IN VOLUME 6

- Completely refreshed FERC and RTO/ISO sections, including FERC Order 2222
- Hydrogen storage? It's getting close
- Avoiding Disputes in Battery Supply Agreements
- New states, including Virginia and South Carolina
- The latest with PJM's capacity rules

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INTRODUCTION

As of today, over 1 gigawatt (GW) of advanced energy storage technologies have been contracted for or deployed in the United States, with nearly all of that capacity coming online in the last decade. New technologies, use cases, and storage-friendly policies and regulations seem to be announced on a weekly basis. But, how did energy storage get here, and where is it going?

Starting in the late 1800s, the popularity of electric lighting spurred the development of small, independent electric grids across the United States, some using direct current to extend power just a few city blocks. Before long, centralized coal, gas, and other large fossil fuel-burning power stations were built, and it became economical to consolidate existing grids and transport electricity across long distances using high-voltage alternating-current transmission lines. Transmission lines began crossing state lines, and the Federal Energy Regulatory Commission (FERC) became responsible for regulating the transfer and sales of wholesale power flowing across the nation's transmission infrastructure. State public utilities commissions, on the other hand, regulated private utilities that used lower-voltage distribution lines to service retail consumers. For many years, providing power was aided by the predictable electrical output of large, centrally located generators fired by steady supplies of fossil fuels, with hydropower and nuclear power plants eventually evolving to play a supporting role in ensuring a stable electricity supply.

Load, or electricity demand, generally increased year-over-year as the country prospered and Americans needed more power for their dishwashers, televisions, and refrigerators.

By the late 20th century, policy makers concerned with power sector emissions and energy security issues began focusing on ways to decarbonize the grid. A combination of tax credits, mandates, grants, and other incentives (led mostly by state governments) spurred the rapid development of carbon-free and renewable power generation assets, including wind and solar facilities. Technological advancements allowed these new renewable facilities to be large enough to provide hundreds of megawatts (MW) of electricity from a central location or to be small enough to power individual homes using solar panels on the roof. Many wind and solar technologies have become cost-competitive with fossil fuel generators and do not require the operational expense of fuel to generate electricity. Many large coal and natural gas plants have ceased operations recently, citing burdensome environmental regulations and competition from cheaper electricity produced by renewable energy resources.

While wind and solar facilities have obvious environmental advantages, they are "intermittent" resources, meaning that their electricity production varies when the sun does not shine and the wind does not blow. Wind- and solar-generated electricity is thus subject to the mercy of Mother Nature and tends not to be produced in exact quantities at the precise moment in time when consumers need it. Too much or too little power on the grid can lead to increased wear-and-tear, short circuits, outages, and high power bills for consumers. States, cities, and (increasingly) corporate actors are nevertheless pressing ahead with their goals to supply more electricity from renewable and distributed resources, which is beginning to stress the grid in unpredictable ways.

Energy storage resources (ESRs) help with the transition from traditional, predictable resources to renewable, intermittent resources and provide many other supplementary benefits to the grid. By capturing energy at the time it is generated and using it on demand at a later time, energy storage technologies are poised to play a key role in the United States' move from large, centrally located power generation to a more distributed and renewable energy supply. The deployment of energy storage systems is expected to grow exponentially in the coming decades, either in stand-alone facilities or collocated with renewable resources to provide more consistent or on-demand power output. Energy storage advocates praise the technology's flexibility, as variants can be installed from residential to utility-scale, perform as generation or load as circumstances warrant, provide several market products, and can be used even to defer massive investments in transmission and distribution infrastructure. With some industry watchers predicting the price of storage to drop by more than 25 percent in the next few years, we expect to see consumers, businesses, regulators, and utilities continue to embrace energy storage technologies to meet their grid needs.

In sum, integrating energy storage technologies into our electric grid infrastructure promises a fundamental reconfiguration of how our nation produces and uses electricity with the hope of resulting in a more reliable, resilient, and cost-effective grid.

This Energy Storage Handbook (Handbook) is designed to be a basic primer on what energy storage is, how it is regulated by federal and state governments, and what sorts of issues are encountered when such projects are financed and developed. While this Handbook is not meant to be a definitive catalog of every energy storage law and issue existing in today's marketplace, we have endeavored to highlight the most common regulatory and development issues faced by our clients and the industries that we serve. We anticipate continuing to update this Handbook as additional states and stakeholders continue to address the implementation of ESRs into the marketplace.

We hope you find it useful and always welcome your feedback.

Buck Endemann
Partner
K&L Gates

ENERGY STORAGE TECHNOLOGIES

The term "energy storage" includes a wide array of technologies that capture energy at one point in time, store it, and release that energy later when it is needed or when it is profitable to do so. While some energy storage technologies have been in commercial use for more than a hundred years (e.g., pumped hydro), many storage technologies are relatively new or are still in the development stage. Below are short descriptions of the most common forms of storage technologies.

Batteries

Battery energy storage technologies involve electrochemical processes that convert stored chemical energy into electrical energy. These different processes generally fall into one of two categories: solid-state batteries and flow batteries.

Solid-state batteries are variations on the conventional batteries that power consumer electronics all over the world. At its most basic level, the solid-state battery is a self-contained cell with one positively charged electrode (cathode) and one negatively charged electrode (anode), with a liquid or gel-based electrolyte in between. When the anode and cathode are connected to an external circuit, the electrolyte allows ions to move from the anode to the cathode within the battery to generate a current that can flow out of the battery onto the external circuit and perform work.

Flow batteries accomplish the same conversion of stored chemical energy into electrical energy but use a completely different design. Rather than storing chemical energy within electrodes, flow batteries store chemical energy in fluid electrolytes that are kept in separate tanks—one positively charged (catholyte) and one negatively charged (anolyte)—and pumped past each other on either side of a permeable membrane. When electrodes on either side of the membrane are connected to an external circuit, the membrane allows ions to move from the anolyte to the catholyte to generate a current that can flow out of the battery onto the external circuit and perform work.

Because of the detached liquid tanks required for the electrolytes, flow batteries offer the potential of nearly unlimited longevity as the tanks can be continuously refilled with freshly charged electrolytes. The current technology for flow batteries, however, is comparatively less developed than solid-state batteries and more costly to build.

Both solid-state batteries and flow batteries have been developed using a variety of different chemical components. For example, solid-state batteries have been developed using lithium-ion, nickel-cadmium, nickel-metal hydride, and sodium-sulfur cells, and flow-battery technologies have included iron-chromium, vanadium, and zinc-bromine batteries. These different electrode and electrolytic materials, battery designs, and varying technological maturities each result in different operating and performance attributes as well as different costs.

California has indicated recently that it plans to ban the internal combustion engine by 2035 and while electric vehicle makers may be well placed to capitalize, meeting rising demand will require a dramatic increase in the energy density of lithium-ion batteries while still improving charging speed and reducing cost. It is anticipated that the next 15 years will constitute an extremely innovative period for energy storage with the lithium-ion battery at the forefront. Such dramatic innovation will be needed in order to provide a cost-effective solution to furthering the distance a car can go on a single charge, or to enter markets like maritime, rail, and aviation. Already there have been material advances as companies develop batteries with silicone anodes and some companies bring prototype secondary lithium metal batteries to the market that claim to double the energy density of lithium-ion batteries and use a separator made of polyimide, a highly heat-resistant plastic that will not burn even at 400° C.

Of course, as more batteries are deployed around the grid, both regulators and companies are keeping a closer eye on their thermal properties.

Flywheels

Flywheel storage technologies convert the energy of a rotating mechanical device into electrical energy. Flywheels use electrical energy to drive a motor that spins a mechanical device to increase its rotational speed, effectively storing electrical energy in the form of kinetic energy, which can then be called on instantaneously to discharge from the spinning rotational device as electricity. Flywheels have very fast response and ramp rates and can go from full discharge to full charge within a few seconds or less. They are well-suited to providing power quality and reliability services as well as fast regulation and frequency response, although their ability to provide long-discharge or capacity services is currently limited. Flywheels have traditionally been made of steel that rotates on conventional bearings; however, in recent years a wide variety of new materials have also been employed, including carbon fiber and magnetic bearings, which have enabled significantly increased rotational speeds and reduced resistance.

Pumped Hydroelectric

Pumped hydroelectric (pumped hydro) storage converts the stored kinetic energy of water held in an elevated retaining pool into electrical energy. Pumped hydro energy storage uses electric energy to power pumps that push water up to the elevated retaining pool, effectively and cheaply storing electrical energy in the form of potential energy. When electricity is less abundant and more expensive, the water is converted back into kinetic and then electrical energy by flowing down from its elevated position through a turbine. Pumped hydro energy storage facilities tend to be large-scale facilities with the ability to respond to large electrical load changes very quickly. Due to the mature state of pumped hydro technology, however, some jurisdictions limit the ability of large-scale pumped hydro facilities to satisfy energy storage mandates favoring new technologies instead.

While using the force of falling water is by far the most common form of "gravitational" storage, other materials have also begun to be tested recently, including gravel- or cement-filled modules that are released from elevated positions to generate electricity following the same basic principles of physics.

Power-to-Gas

Power-to-gas storage converts electrical energy into stored chemical energy in the form of hydrogen gas by using electrical energy to split water into hydrogen and oxygen through the process of electrolysis. The resulting hydrogen (or, upon further conversion, methane) can be stored either in a dedicated storage facility or by injection into the gas grid and then used as a fuel for generating electrical energy at a later time. Power-to-gas storage can have significant benefits when local gas infrastructure is more accessible than power infrastructure for transmission of stored energy. Storing energy in the form of natural gas can also result in benefits from its access to the vast storage capacity of the existing natural gas grid and lower losses during the transmission process.

Increasingly, power-to-gas is viewed as a longer-duration, seasonal storage solution, as well as a way to soak up mid-day renewables generation that may otherwise be curtailed. Recent years have seen a flurry of interest in the hydrogen and renewable natural gas sector, and regulatory agencies have begun to look more seriously into the future of power-to-gas storage solutions.

Thermal

Thermal energy storage can be achieved by a wide variety of technologies using resources that temporarily store energy in the form of heat or cold. For example, thermal energy technologies include using solar radiation to heat molten salt to store energy in the form of heat, which can then be used later to produce steam to power a turbine. Liquid Air Energy Storage (LAES) is a process that uses electrical power to cool air into its liquid state in its storage cycle, then expands the liquid through a turbine in its generation cycle. LAES can be effectively paired with industrial applications and use waste heat to boost efficiency and can provide long-duration, large-capacity energy storage. Thermal energy storage also encompasses technologies that allow buildings to use cheaper, off-peak electricity to power cooling equipment to produce ice or other cooled materials, which can then be used in the building's cooling system when electricity is more expensive. Thermal technologies can vary widely in storage media, facility size, progress of technological development, and cost.

Thermal energy storage can be particularly effective for long-term storage, which is growing increasingly important in markets with greater reliance on renewable energy resources because those resources are often seasonal in nature. For example, over the last decade Denmark has installed a number of storage projects using water in underground pits as the storage medium, where the storage can be charged to 85° C during summer months when solar energy resources are plentiful and discharged to 10–15° C during winter months when the need for electricity is greater and the hours of sunshine are more limited.

Compressed Air Energy Storage (CAES)

CAES facilities compress ambient air and store it under pressure. When the CAES facility is needed to supply electricity, the pressurized air is heated and expanded to power turbines. CAES systems are similar to many pumped energy storage applications in terms of their broad range of applications, including balancing energy, ancillary services, and black start services, as well as CAES's large output and storage capabilities. CAES, however, is still in the early stages of its technological development, with less than a handful of large-scale projects currently in operation around the world.

LAWS AND REGULATIONS SHAPING ENERGY STORAGE DEVELOPMENT

Federal Laws and Regulations

Federal Energy Regulatory Commission Orders

Federal policy and regulatory treatment of ESRs recognizes the importance of this emerging and unique grid resource and provides opportunities to integrate energy storage into wholesale power markets. The FERC is an independent agency within the U.S. Department of Energy (DOE) that, as relevant here, regulates the rates and services of the interstate transmission of electricity and the interstate wholesale of power pursuant to the Federal Power Act (FPA). Under the FPA at Sections 205 and 206, rates and practices affecting rates of electricity transmitting under FERC's jurisdiction must be just and reasonable and not unduly discriminatory or preferential. FERC also certifies and decertifies the status of "Qualifying Facilities" under the Public Utility Regulatory Policies Act of 1978 (PURPA).

FERC appreciates that further change is necessary to fully recognize the value that energy storage provides. FERC continues to review rules governing compensation and interconnection to ensure that storage resources can efficiently interconnect with the grid and receive a just and reasonable rate for their services.

Significant FERC Orders and Policy Statements Affecting Energy Storage

FERC has issued several orders and policy statements creating opportunities for ESRs in ancillary services and other organized wholesale markets. This section provides an overview of those initiatives. Often when FERC issues these rulemakings, it requires the regional transmission organizations and independent system operators (RTOs/ISOs) or other regulated public utility to make a "compliance filing" with further details about how the regulated entity will accomplish the goals of the rulemaking. Often compliance filings present proposed changes to the regulated entity's tariff "on file" with FERC that would be necessary to implement the rule. Most recently, in September 2020, FERC issued Order No. 2222 to remove identified barriers to participation by distributed energy resources (DERs), such as ESRs in the regionally organized markets administered by RTOs/ISOs. Order No. 2222 builds on Order No. 841, a landmark ruling issued in 2018 specifically targeting impediments to ESR market participation in the RTO-administered energy, ancillary services, and capacity markets.

Expansion of Participation of DERs in RTOs/ISOs—Landmark Order No. 2222

In September 2020, FERC issued a landmark order aimed at removing barriers to the participation of DERs in the organized markets for electric energy, capacity, and ancillary services operated by RTOs/ISOs. Order No. 2222 builds on reforms previously undertaken by FERC, and once implemented, will further open up RTO markets to the benefits of competition and innovation.

Order No. 2222 and FERC's new regulations define a DER broadly as "any resource located on the distribution system, any subsystem thereof or behind a customer meter." FERC seeks to foster a "technology-neutral" approach by prohibiting RTOs/ISOs from limiting the kinds of technologies that can join DER aggregations such as ESRs.

Specifically, Order No. 2222 requires that DER aggregations meet a minimum size specified by the RTO/ISO rules, not to exceed 100 kilowatts (kW). FERC also provides flexibility in terms of the system location of DERs and DER aggregations, requiring RTOs/ISOs to propose locational requirements that are "as geographically broad as technically feasible." Recognizing the burden that could be imposed on smaller utilities, Order No. 2222 requires that state regulators determine whether DERs located on their systems can "opt-in" to participate.

FERC's new rule requires that RTOs/ISOs implement these reforms by proposing market rule and other changes to their tariffs within 270 days of the publication of Order No. 2222 in the Federal Register, which likely means by summer of 2021, and requires each RTO/ISO to propose a date on which the reforms will take effect in its markets. FERC will act on those filings and may request subsequent filings.

Expanding Energy Storage Opportunities in Wholesale Markets—Order No. 841 (2018)

In February 2018, FERC issued new rules addressing participation of ESRs in electricity markets operated by RTOs. Largely adopting the proposal issued in November 2016, Order No. 841 seeks to remove barriers for energy storage participation in wholesale capacity, energy, and ancillary services markets.

Order No. 841 directs RTOs/ISOs to revise their tariffs to develop a participation model that better incorporates energy storage into the market, including implementing processes that accommodate the physical and operational characteristics of energy storage systems. FERC mandates that such revisions should:

- Allow ESRs to be eligible to participate in all capacity, energy, and ancillary services markets that the resource is technically capable of providing;
- ensure that storage resources under the participation model can be dispatched and establish the wholesale market clearing price as a wholesale seller and/or buyer;

- account for electric energy storage's physical and operational characteristics (via bidding parameters or other means); and
- set a minimum size requirement for storage resources' participation in the RTO and ISO markets of not more than 100 kW.

In addition to these market requirements, FERC also determined that electric storage resources should pay the wholesale locational marginal price for electric energy that the resource buys from the RTO or ISO (presumably to charge the resource) that is then resold back into the RTO or ISO.

Order No. 841 requires each RTO/ISO to submit compliance filings to implement the tariff changes developed through their stakeholder processes. In December 2018, the RTOs/ISOs began filing tariff revisions to reflect their compliance with Order No. 841. FERC has largely accepted most aspects of the RTO/ISO compliance filings, but continues to drill down on specific nuances and aspects of how the RTOs/ISOs will meet the Order No. 841 requirements. In directing follow-up compliance filings, one issue FERC has focused on is ensuring the tariffs clearly delineate between changes to ESRs for transmission and wholesale services, and charges for retail services. Below is a summary of key takeaways from each compliance filing:

California Independent System Operator, Inc. (CAISO)

CAISO proposed to maintain its existing rules for storage participation in its wholesale market with two key changes. Specifically, CAISO proposed: (1) to lower the minimum size for storage resources to participate from 500 kW to 100 kW and (2) to exempt storage charging energy from transmission charges. As explained by CAISO, CAISO's existing policies are already aimed at achieving the goal of providing more opportunities for storage. In 2011 the CAISO established its "non-generator resource," or "NGR" model for storage resources, which is the CAISO's equivalent to Order No. 841's electric storage resource participation model. The NGR model was developed in response to the directives of FERC Order Nos. 719 and 890 to facilitate the provision of ancillary services by resources capable of both injecting and withdrawing energy. In November 2019, FERC issued an order accepting CAISO's Order No. 841 compliance filing, subject to further compliance. FERC requested that CAISO revise its tariff to better account for physical and operational characteristics of ESRs, revise its tariff to institute minimum size requirements not to exceed 100 kW, revise and explain metering and accounting aspects of its tariff, and require CAISO to provide that it cannot charge wholesale rates for a utility that does not net-out energy purchases associated with an ESR's wholesale charging activities from a host customer's retail bill. In January 2020, CAISO submitted its second compliance filing. In July 2020, FERC issued an order accepting the second compliance filing to become effective 3 December 2019, subject to a further compliance filing due from CAISO within 90 days. FERC accepted in part CAISO's proposed requirement for utilities that do not net-out from retail billing any wholesale energy purchases, but directed CAISO to submit a compliance filing that revises that section to make clear that the provision applies to the wholesale charging activities of all ESRs, not only to NRGs.

New York Independent System Operator, Inc. (NYISO)

NYISO's proposal created a new designation for ESRs—a subset of generators. NYISO also revised its Installed Capacity market requirements to allow ESRs to spread their full capability over four hours to meet the minimum four consecutive-hour run time qualification requirement. However, NYISO's proposal required that NYISO manage a battery's state of charge in the day-ahead market. NYISO requested that its implementation deadline be extended to 1 May 2020, because the software platform upon which the proposed revisions will be implemented is currently undergoing "a significant upgrade."

In December 2019, FERC issued an order accepting and rejecting in part NYISO's Order No. 841 compliance filing, and requiring a follow-up compliance filing that, among other things, created a process for ESRs to de-rate capacity to satisfy minimum run-time needs. In February 2020, NYISO submitted its second compliance filing with revisions to its applicable tariffs.

In August 2020, FERC issued an order modifying the record of requests for rehearing deemed denied and accepting NYISO's second compliance filing to be effective 30 September 2020, and requires a further compliance filing within 90 days for NYISO to clarify how its revisions would exempt certain withdrawals by ESRs from transmission charges.

PJM Interconnection, L.L.C. (PJM)

PJM filed two separate proposals that together constitute its participation model for ESRs, an "ESR Markets and Operations Proposal" and an "ESR Accounting Proposal." PJM's ESR Accounting Proposal would allow PJM to test its proposed accounting methodologies and gather sufficient data before full deployment of the ESR Participation Model. In February 2019, FERC issued a letter order accepting PJM's ESR Accounting Proposal.

PJM's "ESR Markets and Operations Proposal" proposed expanded ESR and Capacity Storage Resource designations to include all storage technologies. In October 2019, FERC issued an order accepting PJM's compliance filing, subject to a further compliance filing and initiating an FPA Section 206 proceeding to investigate PJM's minimum run-time requirements.

In December 2019, PJM submitted another Order No. 841 compliance filing to revise its tariff and operating agreement. In July 2020, FERC issued an order accepting PJM's compliance filing to be effective December 2019, with certain specific revisions to be effective in March 2024, subject to a further compliance filing within 90 days to clarify how current or new tariff provisions will prohibit all distribution-connected ESRs from double-paying for the same charging energy.

Southwest Power Pool Inc. (SPP)

SPP filed a compliance proposal that largely tracks the order's mandates. While SPP proposed a participation model for ESRs to participate in the market under the resource registration name Market Storage Resources, its proposal also allowed ESRs to participate through existing participation models if they meet the requirements. SPP also proposed allowing ESRs to fulfill Load Serving Entity resource adequacy requirements if the ESR meets the continuous run time requirement applied to all resource types. Additionally, SPP assumed that the market participant (rather than system operator) would manage the ESR's state of charge.

In October 2019, FERC issued an order accepting SPP's compliance filing to be effective in nine months, and instituted a proceeding under FPA Section 206 to direct SPP to include a resource adequacy minimum run-time in its tariff. The order also required a further compliance filing that, among other things, defined the term "Ramp-Rate-Up" as used in the tariff and include the rate at which ESRs could move from zero to Maximum Discharge Limit within that definition. In December 2019, SPP filed a follow-up compliance filing.

In July 2020, FERC issued another order that accepted SPP's compliance filing, but required a further compliance filing within 90 days that either removes registration provisions in the tariff requiring certain ESRs to provide certification that it is not precluded by a retail regulatory authority or clarify how its proposed language does so.

Also, in February 2020, FERC issued an order allowing SPP to defer the

effective date for the revisions to its tariff in compliance with Order No. 841, setting the effective date for August 2021.

Midcontinent Independent System Operator, Inc. (MISO)

MISO's electric storage participation program applies to all types of energy storage, including resources serving as non-wires alternatives to transmission and distribution needs. MISO proposed to alter the definition of "commitment status" for ESRs, allowing them to signal their availability and the manner in which they will provide products and services over time periods. MISO also requires execution of a new *pro forma* Distribution ESR Agreement for ESRs that connect to the distribution system. Commenters requested an explanation of whether and to what extent an ESR will be liable for transmission charges. Since MISO's effective date for implementation in December 2019, ESRs are able to register for the quarterly update of MISO's proposed models.

In November 2019, FERC issued an order accepting MISO's Order No. 841 compliance filing, subject to a further compliance filing. In January 2020, MISO submitted its second Order No. 841 compliance filing. In August 2020, FERC issued an order modifying the record as the rehearing request was deemed denied by operation of law, and accepting MISO's second compliance filing to be effective 6 June 2022, subject to a further compliance filing within 90 days to provide, among other things, an exemption in the tariff from transmission charges for ESRs withdrawing energy as dispatched due to their down ramp capability, and update the tariff to require ESRs to participate in both wholesale and retail markets.

ISO New England Inc. (ISO-NE)

IISO-NE's compliance proposal explained how recent tariff changes, including adding new categories of storage resources, meet Order No. 841 requirements. As part of its Order No. 841 compliance, ISO-NE also proposed revisions in October 2018 that were accepted by the FERC in February 2019. The proposed revisions apply to resources that meet the requirements of a Continuous Storage Facility. Among other things, Continuous Storage Resources must be able to transition between the facility's maximum output and maximum consumption in 10 minutes or less. The new rules provide mechanisms for Continuous Storage Resources to participate in ISO-NE's energy, reserves, and regulation markets. The December 2019 Compliance filing proposed terms to distinguish between fast-responding storage resources (i.e., continuous storage facilities) and pumped-storage hydro-power (i.e., binary storage facilities). Both types may participate in the ISO-NE's markets under different registration requirements and designations. ISO-NE's provisions stated that implementation would occur by 3 December 2019 for the majority of its measures. Among other issues, protests of the filing expressed concern over ISO-NE's proposed automatic de-rating of ESRs energy output capability, which ensures 60-minute availability to provide reserve, but protesters assert it is inconsistent with Order No. 841. In November 2019, FERC issued an order accepting MISO's compliance filing, subject to a further compliance filing.

In February 2020, ISO-NE submitted a second compliance filing to revise ISO-NE's tariff. In August 2020, FERC accepted ISO-NE's second compliance filing to be effective 3 December 2019, with a limited number of further revisions to be effective 1 January 2026. The order requires a further compliance filing within 90 days to specify that it will not apply transmission charges to ESRs in certain circumstances, and a further compliance filing within one year, which specifies how ISO-NE accounts for State of Charge and Duration Characteristics of ESRs in the day-ahead market.

In May 2019, FERC issued Order No. 841-A denying rehearing on whether to allow states to decide if electric storage resources in their state that are located behind a retail meter or on the distribution system are permitted to participate in the RTO/ISO markets. The order also clarified several aspects of Order No. 841, emphasizing throughout that RTOs/ISOs have flexibility to allow energy storage to participate fully in their markets.

In July 2020, the U.S. Court of Appeals for the D.C. Circuit issued its opinion in *National Ass'n of Regulatory Utility*

Commissioners v. Federal Energy Regulatory Commission, which upheld FERC's Order Nos. 841 and 841-A, finding that it does not run afoul of the FPA and "does not usurp state power. . . ." 964 F.3d 1177, 1188 (D.C. Cir. 2020) (internal citations omitted). The court concluded that FERC must regulate the wholesale market, including wholesale rates and the rules that govern them. The court found that Order No. 841 only targets the manner in which ESRs may participate in wholesale markets and allows for increased wholesale competition, reducing wholesale rates.

Reform of Generator Interconnection Procedures and Agreements— Order No. 845 (2018)

In April 2018, FERC issued a Final Rule to amend the *pro forma* Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA) to improve reliability, promote more informed interconnections, and enhance generators' interconnection processes by eliminating inefficiencies and bottlenecks. Order No. 845's reforms to the interconnection process create significant opportunity for ESRs. As an initial matter, Order No. 845 reforms the pro forma interconnection agreements and procedures to include energy storage in its relevant definitions. The order also allows customers to connect at less than nameplate capacity and to take advantage of excess interconnection capacity already available on the transmission system. Both of these developments are expected to benefit ESRs because they will allow those resources to pair with existing generation with little or no additional interconnection costs. Similar to FERC's recent Order No. 841, with Order No. 845, FERC continues to unlock opportunities for energy storage to participate in the wholesale power markets.

In February 2019, FERC issued Order No. 845-A that clarified and revised aspects of Order No. 845 based on the comments and issues that had been raised since its issuance. Relevant to energy storage, Order No. 845-A clarifies that for an entity to take advantage of surplus interconnection capacity, it can only do so if the surplus interconnection capacity can be accommodated without requiring the construction of new network upgrades. This will be relevant as the transmission provider analyzes the impacts of storage projects using excess interconnection capacity of a different type of generation resource. Order No. 845-A also clarified that transmission providers must develop a definition of permissible technology changes that the interconnection process will accommodate without the loss of a queue position pursuant to the material modification provisions of the LGIP. The effective date for Order No. 845-A is 20 May 2019.

Later, in August 2019, FERC issued Order 845-B further clarifying aspects of Order Nos. 845 and 845-A based on comments raised in the orders. These clarifications involve the provisions of

the *pro forma* agreements dealing with a transmission owner's option to build and indemnification provisions.

Requirements to Provide Primary Frequency Response—Order No. 842 (2018)

In February 2018, FERC amended the pro forma LGIA and the pro forma Small Generator Interconnection Agreement (SGIA) to require all new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC also establishes certain uniform minimum operating requirements in the pro forma LGIA and pro forma SGIA, including maximum droop and deadband parameters and provisions for timely and sustained response.

The notice of proposed rulemaking that preceded the final rule included no provisions specific to electric storage resources. However, several commenters raised concerns that by failing to address electric storage resources' unique technical attributes, the proposed requirements could pose an unduly discriminatory burden on storage resources. As a result, the final rule adopted changes specific to electric storage resources. Specifically, the final rule required transmission providers to include in their LGIAs and SGIAs specific accommodations and limitations on when electric storage resources will be required to provide primary frequency response. For example, new interconnecting electric storage resources will be required to specify an operating range representing the minimum and maximum state of charge over which the resource will provide primary frequency response. The Final Rule became effective on 15 May 2018.

Policy Statement on Cost Recovery for Electric Storage Resources (2017)

In January 2017, FERC issued a policy statement clarifying that an electric storage resource may provide transmission or grid support services at a cost-based rate while also participating in the RTO/ISO markets and earning market-based revenues. The policy statement, however, acknowledged that implementation details would need to be addressed on a case-by-case basis. ESRs seeking to provide transmission or grid support services at a cost-based rate while also recovering market-based revenues will need to address: (1) the potential for double recovery if the ESR provides services at both cost-based and market-based rates; (2) the potential for the ESR's combined rate recovery to cause adverse market impacts; and (3) the level of control an RTO/ISO may have over operating an electric storage resource without jeopardizing independence.

Shortage Pricing Reforms—Order No. 825 (2016)

In Order No. 825, FERC established settlement interval and shortage pricing requirements for organized markets. Order No. 825 requires each RTO/ISO to trigger shortage pricing for a dispatch interval during which a shortage of energy or operating reserves occurs. The shortage pricing requirement promulgated in Order No. 825 is expected to encourage investment in energy storage, as one of the primary goals of shortage pricing is to facilitate long-term market entry of new supply resources (i.e., storage resources) and exit of resources that are no longer economic.

Additional Opportunities for Ancillary Services Revenues—Order No. 819 (2015)

Building on Order No. 784's reforms, FERC's Order No. 819 expanded the scope of ancillary services that can be provided by ESRs to include primary frequency response service (as distinct from regulation service). Order No. 819 defines primary frequency response service as "a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over." As a result, ESRs that can capably provide such service have the ability to participate in a new revenue stream available to them.

Interconnection of Storage Resources through Small Generator Interconnection Procedures (SGIP)—Order No. 792 (2013)

FERC amended its pro forma Small Generator Interconnection Procedures and pro forma Small Generator Interconnection Agreement to cover "storage for later injection of electricity." The SGIP applies to generating facilities and storage resources that are less than 20 MW and allows for fast track processing of interconnection requests for facilities that satisfy certain eligibility criteria. To determine whether a storage device can interconnect under the SGIP or whether it qualifies for the fast track process, the storage device's capacity is deemed to be equal to the maximum capacity that the device is capable of injecting into the transmission provider's system.

Opportunity for Ancillary Services Revenues—Order No. 784 (2013)

Order No. 784 provided revenue opportunities for ESRs by allowing these resources to sell imbalance and operating reserve services at market-based rates. Previously, such services had been provided by the transmission operator at cost-of-service or by self-supply. In addition to creating a new revenue opportunity in which ESRs could participate, Order 784 also required transmission providers to place greater value on speed, accuracy, and performance when procuring ancillary services.

Frequency Regulation—Order No. 755 (2011)

Frequency regulation service is one of the tools used to balance short-term supply and demand on the transmission system. In 2011, FERC adjusted its frequency regulation compensation rules to recognize and properly reward the fast-ramping capabilities of resources like battery energy storage technologies.

FERC determined that the existing frequency regulation compensation practices in RTOs/ISOs resulted in unjust and discriminatory rates because the compensation methods in those markets failed to acknowledge frequency regulation services provided by faster-ramping resources. Order No. 755 required RTOs/ISOs to file compliance tariffs that would compensate frequency regulation resources based on the actual service that those resources provided. This new compensation system included a capacity payment accounting for the marginal unit's opportunity costs and a performance payment that rewarded a particular resource when it accurately followed a dispatch signal. Overall, Order No. 755 increased the pay for quick-response sources that bid into frequency regulation service markets, such as storage batteries or flywheels.

Demand Response Opportunities—Order No. 719 (2008) and Landmark Order No. 745 (2011)

Because behind-the-meter energy storage, in particular, can serve as an effective demand response resource, FERC's seminal demand response orders also opened revenue streams for energy storage systems. FERC issued Order No. 719 in 2008 and directed RTOs and ISOs to make several reforms to ensure comparable treatment of demand response resources in organized energy markets. The reforms included requiring RTOs and ISO to create new bidding parameters and accept bids from demand response resources for

ancillary services. In 2011, FERC issued Order No. 745 to ensure that demand response resources participating in the organized markets were compensated at the same rate as generation. Although generators challenged FERC's authority to issue Order No. 745, in *EPSA v. FERC*, the Supreme Court found that the FPA authorized Order No. 745's regulation of demand response, which did not impinge on state jurisdiction.

ESRs in Transmission Planning - Landmark Order No. 1000 (2011)

ESRs are playing a greater role in transmission planning processes as "nonwire" alternatives. In Order No. 1000, FERC required transmission providers to consider proposed

"nontransmission alternatives"—including energy storage, demand response, and distributed generation—on a comparable basis with transmission solutions as part of their regional transmission planning. Despite this requirement, Order No. 1000 did not provide concrete instructions on how to achieve comparable treatment for nontransmission alternatives in such planning efforts, and cost recovery issues for nontransmission alternatives remain unresolved. Accordingly, while Order No. 1000 attempted to create opportunities for ESRs to be considered in the regional planning processes, and some progress has been made, challenges and uncertainty continue to hamper ESR deployment.

Opportunities for Non-Generation Resources—Order No. 890 (2007)

A key moment in the ability for ESRs to participate in wholesale markets began with the implementation of FERC Order No. 890. One aspect of Order No. 890's reforms to prevent undue discrimination and preference in transmission service involved changes to FERC's pro forma open access transmission tariff that opened energy and ancillary services markets to non-generation resources, including energy storage. In particular, the reforms opened markets for non-generation resources capable of providing reactive supply, voltage control, regulation, frequency response, imbalance, spinning, and supplemental reserve services.

New FERC Orders Impacting ESRs

FERC Denies Complaint Against NYISO on Buyer-Side Mitigation Rules for ESRs

In February 2020, FERC denied a complaint from the New York Public Service Commission and the New York State Energy Research and Development Authority against NYISO, alleging that NYISO's buyer-side market power mitigation rules were unjust, unreasonable, and unduly discriminatory because they limit ESRs' ability to participate in the ISO's capacity market and hinder governmental policy objectives. FERC found the complaint failed to meet the burden under FPA Section 206. FERC explained that the NYISO buyer-side mitigation rules for ESRs in New York do "not divest New York State of its jurisdiction over generation facilities or its authority to set generation-related environmental goals." Rather, FERC found that the NYISO's buyer-side mitigation rules as applied to ESRs "appropriately protects the capacity market from the price suppressive effects of resources receiving out-of-market support while preserving the cooperative federalism approach established under the FPA."

FERC Denies New England Ratepayer Association Petition Seeking FERC's Exclusive Jurisdiction Over Wholesale Energy Sales from Behind-the-Meter Generation

In April 2020, New England Ratepayer Association's (NERA) filed a petition for declaratory order, seeking FERC's declaration that FERC holds exclusive jurisdiction over wholesale energy sales from behind-the-meter generation and requiring that the rates for such sales be priced pursuant to the FPA or PURPA, when applicable. Specifically, NERA asked FERC to declare jurisdiction over energy sales of rooftop solar and other DERs on the customer side whenever the output exceeds the customer's demand, or the energy is meant to bypass customer load. NERA characterized "full net metering" as "a practice through which an electricity consumer produces electric energy from a generation source (most often solar panels) that is located on the same side of the retail meter as the customer's load." Historically, the FERC sees such transactions as retail in nature and regulated by the states. NERA argued, however, that the energy exceeding customer demand or bypassing customer load is sold to a utility for resale to customers, making them wholesale sales, and therefore, subject to FERC's jurisdiction.

In July 2020, FERC dismissed the petition. FERC began its analysis with a reminder: "Declaratory orders to terminate a controversy or remove uncertainty are discretionary." FERC then used its discretion not to address the issues presented, as they did not "warrant a generic statement" from FERC. FERC found that NERA never identified "a specific controversy or harm" to be addressed. Further, FERC found that to the extent NERA is concerned that certain New England state regulatory authorities are not pricing Qualifying Facility sales in accordance with PURPA, the petition did not meet PURPA's requirements for enforcement.

American Electric Power Seeks FERC Approval Assigning an ESR as Transmission Asset

In July 2020, utility American Electric Power (AEP) filed a petition for declaratory order, seeking for FERC to confirm that the Middle Creek energy storage project is a transmission asset, which would make it eligible for cost-of-service recovery under PJM's tariff through AEP's transmission formula rates. AEP's petition concerns the narrow issue of categorizing this specific project, but PJM is also currently working through its own stakeholder process of how to properly categorize such types of projects. FERC has not yet ruled on the petition.

FERC Finds ESRs Can Be a "Load-Shape Modifying Device" for Demand Response

Ruling on a dispute over interpreting the terms of a full requirements power purchase agreement, FERC found that Order No. 841 validated that ESRs may be deployed as demand response devices by a municipal purchaser. FERC noted that none of the language of the full requirements contract at issue prohibited using the ESRs for demand response, and, when used as proposed, it would be indistinguishable from demand response resources that modify the timing of energy consumption. When used as proposed, FERC stated the ESR "technology is inherently a load-shape modifying device, designed not to reduce a customer's overall load but to shift the incidence of such load, i.e., to manage the customer's demands."

Federal Tax Incentives

For many years, federal tax incentives have played an important role in developing preferred conventional and renewable energy resources. ESRs can also benefit from certain federal tax incentives, particularly when those resources are paired with renewable energy facilities that themselves qualify for federal tax incentives. Although federal legislative attempts have failed to provide the energy storage industry with its own tax credit, some energy storage may qualify for an investment tax credit (ITC) or a production tax credit (PTC) when developed alongside qualifying resources. In addition, guidance released by the Internal Revenue Service (IRS) in March 2018 that concerns the residential tax credit available under Code Section 25D implies that storage installed for use with a facility that qualifies for the ITC after such facility has been placed in service *may* separately qualify for the ITC; however, the guidance does not state that conclusion directly. There are also arguments, but considerably less certainty that storage installed after a PTC-qualified facility is placed in service may separately qualify for the ITC if such facility would have qualified for the ITC.

There is hope that the U.S. Department of Treasury will release additional guidance regarding the qualification of energy storage assets for the ITC. On 20 September 2018, Senators Tim Scott (R-SC) and Michael Bennet (D-CO) sent a letter to Treasury Secretary Mnuchin asking him to provide that guidance, particularly in regard to whether storage assets installed at operating ITC-eligible facilities qualify for the ITC. In addition, on 4 April 2019, U.S. Representative Mike Doyle (D-PA-18), together with co-sponsors, U.S. Representatives Linda Sánchez (D-CA-38) and Earl Blumenauer (D-OR-3), introduced the Energy Storage Tax Incentive and Deployment Act, which would authorize the ITC for standalone storage.

Tax Credits for Renewable Energy Property, Generally

Section 48 of the Internal Revenue Code (the Code) provides a 10 percent or 30 percent ITC for an investment in certain renewable energy facilities in the year in which such facilities are placed in service. Solar facilities currently qualify for a 30 percent ITC. Code Section 45 provides for PTCs when electricity produced by certain renewable energy facilities (usually wind) is sold to a third party during the 10 years after the facility was "placed in service." The PTC rate is adjusted annually, but is currently being phased out for most technologies. (The maximum PTC rate applies to facilities the construction of which began in 2016 or earlier and that meet certain other requirements.) The ITC will begin phasing out for solar projects that begin construction in 2020 or a later year. All solar projects must be placed in service by the end of 2023 to qualify for an ITC rate greater than 10 percent.

YEAR CONSTRUCTION BEGAN	LAST YEAR TO PLACE FACILITY IN SERVICE	ITC RATE
2019	2023*	30%
2020	2023	26%
2021	2023	22%
2022, and thereafter	N/A	10%

**If construction begins in 2019, the project should be placed in service within four years after the day on which construction begins.*

Qualification of Energy Storage Property for the ITC and PTC

Energy storage property generally should qualify for the ITC when the storage equipment is placed in service at the same time as an ITC-qualified facility (generally, solar) if at least 75 percent of the power stored in the battery comes from qualified resources.

Energy storage property also should qualify for the ITC when the storage equipment is placed in service at the same time as a repowered facility, provided that the requirements above are met *and* the value of the used equipment incorporated into the facility is worth no more than 20 percent of the total value of the facility. This provides opportunities to claim the ITC for energy storage devices installed at proven qualified energy facilities, which may be useful in the secondary market for facilities that have been operating longer than the ITC or 1603 grant recapture period (five years following placement in service).

Standalone storage does not currently qualify for the ITC, but legislation was recently introduced to create a new category of ITC for standalone storage. In addition, see the discussion below about Opportunity Zones (OZ) for additional types of federal incentives.

Although energy storage technologies that store electricity produced by a qualified energy facility should independently qualify the residential solar energy credit under Code Section 25D, it is not clear that they would qualify for the ITC. Private Letter Ruling 201809003,[1] which was released by the IRS on 2 March 2018, concludes that the cost of a battery installed to store power produced by a residential solar system the original installation of which had already been completed *separately* qualified for the Code Section 25D residential tax credit. Importantly, the IRS expressly stated in PLR 201809003 that it will treat the battery as property that "uses solar energy to generate electricity," provided that only solar energy is used to charge it. This is important because the same phrase is used in Code Section 48 to describe solar energy property that qualifies for the ITC. There are other similarities between the two credits that are also compelling. For example, both credits are only available in respect of the year in which the relevant property is first used. For Code Section 25D purposes, this is the year in which the original installation of the property is completed. For Code Section 48 purposes, this is the year in which the property is placed in service, a very similar test. In addition, Treasury Regulations applicable to Code Section 48 expressly contemplate storage as credit qualifying property. Additionally, although not clear, these Treasury Regulations arguably apply even if the storage asset is not placed in service at the same time as the solar panels or similar property that input energy to the storage asset. Nonetheless,

1 Private Letter Rulings are binding only in respect of the taxpayer who requested the ruling based exclusively on the facts represented in the ruling requested. Accordingly, other taxpayers may not rely on any conclusion in a Private Letter Ruling, but such rulings may be informative of IRS positions on certain matters.

the qualification of any storage asset, particularly an asset installed after a related ITC-qualified facility has been placed in service, for the ITC should be evaluated carefully before claiming the ITC in respect of the relevant costs.

The PTC is available only for electricity produced by a "qualified facility," which generally includes all property that is functionally interdependent and is used to produce electricity using a qualified resource (for example, wind). This property generally includes, for example, equipment used for power conditioning, which may include voltage regulation, which may, in turn, be provided by certain energy storage systems. However, because the PTC is available only for electricity *produced* by a qualified facility, there is some uncertainty about whether the PTC is available for power stored in and later released from on-site energy storage equipment independent of the power generated from a qualifying facility. In addition, many offtakers will not pay for power lost during storage, which would reduce the amount of PTC available.

Given that PLR 201809003 concluded that a storage asset may qualify for the ITC independently of the facility that inputs energy to the storage asset if all the relevant criteria is met, it is possible—but far from certain—that the cost of a storage asset installed at a facility producing power that qualifies for the PTC may separately qualify for the ITC if such facility would also qualify for the ITC. This is a limited class of assets, particularly given the current sunset periods for "crossover" facilities that can qualify under both Code Sections 45 and 48 at the facility owner's election. In addition, although not certain, it seems the IRS would have very good arguments that the PTC would not be available in respect of power stored in a storage facility located "behind the meter" if the storage facility owner claims the ITC in respect of the cost of such storage facility. *Ultimately, this argument is untested and should be evaluated very carefully before claiming the ITC in respect of any storage asset installed to store power at a PTC-qualified facility.*

Depreciation Deductions

For federal income tax purposes, the basis of tangible property, including energy storage equipment, is recovered over a specified useful life using one of several methods. The favored method is the modified accelerated cost recovery system (MACRS), which generally provides for accelerated depreciation deductions in the earlier years of a property's useful life. Energy storage equipment incorporated into an ITC-qualified solar facility and placed in service concurrently with that facility can be depreciated using the MACRS method over five years. Otherwise, energy storage equipment is generally depreciated using the MACRS method over seven years.

Renewable energy property that is placed in service before 2023 generally should qualify for immediate expensing, sometimes referred to as "bonus" depreciation. After 2022, bonus depreciation will continue to be available through 2026, but at reduced rates. While bonus depreciation also applies to used property, used property may not account for 20 percent or more of the value of renewable energy property that is incorporated into a project that is intended to qualify for the ITC.

Energy Storage in Opportunity Zones

The OZ incentive provides attractive tax benefits for investors with capital gains and, unlike the ITC, is technology agnostic and available for standalone storage. The program is available for investments in qualifying assets located in one of the more than 8,700 geographic areas that is designated as an OZ. For storage plus facilities, the OZ incentive also can be combined with the ITC and PTC. In addition, *any* U.S. person and certain non-U.S. persons can invest in a qualified opportunity fund (QOF) and use the OZ incentive. This includes individuals, corporations, partnerships, and trusts. Partners investing capital gains from a partnership have a longer window to invest in a QOF than the partnership would.

The benefits of the OZ incentive are available when a taxpayer disposes of a capital asset and, within 180 days, invests the proceeds in a QOF that invests in OZ property, either through a direct investment in tangible qualified opportunity zone business property or a newly-issued equity interest in a partnership (including an LLC) or corporation operating a business in a qualified opportunity zone business (QOZB). A QOF can be a corporation or a partnership (including an LLC) for U.S. federal income tax purposes and can function as an investment fund, a private investment entity, or many options in between. A variety of requirements apply to QOFs and QOZBs. For example, at least 90 percent of the QOF's assets (measured by cost or value, depending on the applicable facts) must be invested in OZ property as described above and at least 70 percent of a QOZB's tangible assets must be located in one or more OZ areas.

Owning storage and storage plus systems through a QOF must be carefully structured in order to ensure compliance with applicable regulations and maximize tax benefits and the investors' rate of return.

The OZ incentive consists of three tax benefits for investors:

- First, federal taxes on capital gains invested in QOFs may be deferred up to the 2026 tax year.
- Second, if the taxpayer holds the QOF investment for at least five years, the gain ultimately recognized may be reduced by 10 percent. The gain may be further reduced by another 5 percent if the taxpayer holds the QOF investment for at least seven years.
- Third, if the taxpayer holds the QOF investment for at least 10 years, capital gains realized upon disposition of the investment are free from federal income tax due to a step up in basis of the investment to its fair market value at the time of disposition.

As attractive as the program is, owning storage and storage plus systems through a QOF must be carefully structured in order to ensure compliance with applicable regulations and maximize tax benefits and the investors' rate of return. In addition, the facts and circumstances applicable to each investor require that QOF structures be somewhat tailored to different investors to account for other U.S. federal income tax limitations.

State Laws, Regulations, and Policies

ARIZONA

While the Arizona Legislature has not enacted any significant laws relating to energy storage, the Arizona Corporation Commission (ACC) has promoted energy storage technology development and deployment, particularly at the retail level.

In August 2016, the ACC began considering changes to the ACC's Renewable Energy Standard and Tariff (REST) rules, which were originally established in 2006. The failed initiative proposed to increase Arizona's Renewable Portfolio Standard from 15 percent by 2025 to 30 percent in 2030, and also considered revising the existing REST rules to incorporate the development and adoption of energy storage solutions to better benefit Arizona ratepayers. In 2018, a ballot initiative to amend the state's constitution and require utilities to provide 50 percent of renewable energy by 2030 failed. ACC Commissioner Andy Tobin proposed a competing RPS Arizona's Energy Standard Modernization Plan in 2018, in which the state would have to meet an 80 percent clean energy target by 2050 coupled with a 3,000 MWt energy storage procurement target by 2030. However, this initiative also failed.

Recently in July 2020, Utilities Division staff at the ACC again recommended that the ACC's Energy Rules be entirely revised. The suggested revisions include a Distributed Renewable Storage standard that requires electric utilities' to achieve at least 10 percent of retail kWh sales from distributed natural storage by 2035. The proposed revisions also call for at least 50 percent of utilities' retail kWh sales to be derived from renewable energy resource by 2035 and 100 percent of sales from renewable sources by 2050. The ACC is currently reviewing comments on the recommended changes, but has not yet started the formal rulemaking procedure.

Outside of the REST rule proceeding, the ACC has spurred the adoption of energy storage technology by using utility mandates. The ACC recently ordered Arizona Public Service (APS), Arizona's largest utility, to develop a US$6 million residential demand response/ load management program to facilitate residential energy storage technology. APS has proposed a "reverse demand response" program that would pay storage to charge at periods of electricity oversupply. In February 2017, the ACC ordered Tucson Electric Power Company (TEPCO) to develop a similar US$1.3 million program. In January 2018, the ACC proposed a "clean peak" program that includes a 3,000 MW energy storage procurement target for 2030, with the goal of making renewable facilities dispatchable on command during periods of peak demand. Most recently, on 12 March 2018, the ACC instituted a moratorium on utilities procuring capacity from new gas plants over 150 MW for the remainder of 2018 and instead required the state's utilities to perform an independent analysis of the costs of "alternative energy storage options."

Salt River Project and TEPCO have also each entered into power purchase agreements (PPA) to buy power from two battery storage systems (10 MW and 30 MW, respectively), each of which will be paired with a corresponding solar facility. TEPCO also announced recently that its partner, E.On North America, has completed development of an additional 10 MW battery storage project, paired with a 2 MW solar array, that will provide frequency response and voltage control on TEPCO's system. APS, UNS Energy, and TEPCO have all included significant amounts of energy storage in their 2017 Integrated Resource Plans, and in January 2018 TEPCO issued an RFP for up to 150 MW of wind or wind plus energy storage and in June 2018 APS issued an RFP to equip existing solar farms with up to 106 MW of battery storage.

Independent of ACC initiatives, Arizona utilities are investing in the development of utility-scale combined energy storage/solar facilities, in large part due to Arizona's favorable climate for solar generation. In late 2016, APS announced plans to develop 4 MW of energy storage in connection with its Solar Partner Program, through which APS intends to study the potential impact of batteries on its system. APS recently announced it will add 850 MW of battery storage by 2025 by adding batteries to existing solar facilities, deploying new battery resources, and contracting third-party-owned storage. On the residential side, in November 2017, APS selected Sunverge Energy to participate in a pilot program that would analyze how integrating storage with solar and home energy management software could deliver increased customer value. Arizona will also be home to the country's first planned community microgrid that will integrate community-wide demand-response and energy storage systems with smart-home automation systems, which will allow homes to draw upon stored energy during peak periods while soaking up excess mid-day solar and early morning nuclear generation.

Since a fire at an APS facility in April 2019, Arizona cities have begun enacting new laws regulating how large batteries are stored. The municipal laws apply to homeowners, businesses, and schools that install large batteries to store energy from solar panels or for electric vehicles. Notably, however, the restrictions include new rules for public utilities that build battery storage facilities along the grid to store energy, which may restrict the location of future projects.

CALIFORNIA

California's Energy Storage Mandates and Rebates

California has several laws and incentives driving the adoption of large-scale and behind-the-meter ESRs, making it the clear leader in installed and procured energy storage systems. Many of these initiatives are set forth in the California Energy Storage Roadmap, an interagency guidance document jointly developed by the CAISO, the California Energy Commission (CEC), and the California Public Utilities Commission (CPUC).

California's primary legislative efforts include two laws requiring utilities to procure significant amounts of ESRs and a revamped and recently extended Self-Generation Incentive Program (SGIP) that provides consumer rebates worth approximately US$800 million through 2026. California has also taken the lead in its efforts to properly value energy storage technologies' many contributions to grid stability and reliability. As of December 2019, the CPUC estimated that there is 506 MW of energy storage operating on the California grid, including both front of and behind-the-meter assets.

In January 2018, the CPUC issued D.18-01-003, which included 12 rules governing how an ESR could participate in several grid domains at the same time (also known as "Multiple Use Applications"). A CPUC working group issued recommendations in August 2018 regarding utility cost recovery, costs for charging storage assets, resource adequacy refinements, and other issues. The CPUC continues to consider how behind-the-meter storage resources can contribute to grid reliability and how to refine interconnection and rate tariffs to enable additional storage and microgrid assets to address California's steep evening ramp.

Other administrative changes are more subtle, but no less significant. Every two years, the CPUC establishes a "reference system portfolio" that evaluates the optimal mix of resources to meet greenhouse gas emissions limits. California's Load Serving Entities must use the reference system portfolio in developing their Integrated Resource Plans. In March 2020, the CPUC released its revised reference system portfolio calling for approximately 1 GW of long-duration storage by 2026.

California AB 2514—The "Original" Energy Storage Procurement Bill

California Energy Storage Bill AB 2514 became law in September 2010. With the goal of encouraging widespread adoption of energy storage, the bill required the CPUC to determine appropriate targets for each large investor-owned utility (IOU) to procure viable and cost-effective energy storage systems. The bill also required the governing board of each local municipally-owned electric utility to determine appropriate targets.

Under AB 2514 and related CPUC decision-making, California IOUs are required to collectively procure and install 1,325 MW of energy storage by 2024 (the deadlines are generally delayed about a year for municipally-owned

utilities, like the Los Angeles Department of Water and Power (LADWP)). For IOUs, the CPUC divided the 1,325 MW storage target into biennial procurement targets to be met in 2014, 2016, 2018, and 2020. For each year, the 1,325 MW is further broken down into separate requirements for transmission-connected, distribution-connected, and customer-side energy storage procurements, as listed in the below table:

Utility	*Storage Grid Domain Point of Interconnection*	*2014*	*2016*	*2018*	*2020*	*Total*
SOUTHERN CALIFORNIA EDISON	Transmission	50	65	85	110	310
	Distribution	30	40	50	65	185
	Customer	10	15	25	35	85
	Subtotal	**90**	**120**	**160**	**210**	**580**
PACIFIC GAS AND ELECTRIC	Transmission	50	65	85	110	310
	Distribution	30	40	50	65	185
	Customer	10	15	25	35	85
	Subtotal	**90**	**120**	**160**	**210**	**580**
SAN DIEGO GAS AND ELECTRIC	Transmission	10	15	22	33	80
	Distribution	7	10	15	23	55
	Customer	3	5	8	14	30
	Subtotal	**20**	**30**	**45**	**70**	**165**
TOTALS		**200**	**270**	**365**	**490**	**1,325**

The CPUC's targets allow each IOU to defer up to 80 percent of its required storage targets to later periods if it is unable to find viable projects. To spur the research and development of new technologies, certain mature storage technologies, like pumped hydro over 50 MW, are ineligible to be counted toward these targets.

To guide the procurement processes, every two years each IOU is required to submit to the CPUC an energy storage procurement plan incorporating state mandates to, among other things, integrate renewable resources, reduce peak demand, reduce fossil fuel use, and avoid or delay transmission and distribution upgrades.

California utilities are meeting their storage targets in several different ways. While the IOUs solicit projects through biennial, storage-specific Request for Offer (RFO) programs, most of the utilities have also procured significant storage resources through Local Capacity RFOs and Preferred Resources pilot programs. In response to the Aliso Canyon gas storage shutdown to mitigate the risk of insufficient gas-fired generation, Greensmith Energy, AES Energy Storage, and other storage companies each successfully bid, installed, and interconnected three lithium-ion battery projects with a cumulative total of 70 MW (four-hour units), an effort that gave Southern California Edison (SCE) and the CPUC confidence that significant amounts of energy storage could be added to the grid quickly and efficiently. Additional storage projects rounded out the Aliso Canyon effort to approximately 90 MW. In addition to the Aliso Canyon RFO, SCE procured approximately 260 MW through its 2013 Local Capacity Requirements RFO and approximately 120 MW through its Preferred Resources Pilot 2 RFO. SCE has also signed contracts to use 195 MW of storage and other preferred resources to meet the Moorpark sub-area's local capacity need, which SCE previously proposed to meet by building a new 262 MW gas-fired generator. And in May 2020, SCE announced that it had signed seven storage contracts (many co-located with renewable resources) for a combined 770 MW, easily the largest storage deal to date.

The CPUC has also approved Pacific Gas and Electric Company (PG&E) 's request to replace three natural gas-fired power plants in the Moss Landing area with 567.5 MW / 2,270 megawatt hour (MWh) of battery storage projects. The 300 MW project from Vistra Energy and the 182.5 MW project from Tesla, Inc. (Tesla) would be one of the largest battery storage projects in the world. PG&E is also planning to replace an aging 165 MW facility in Oakland with a mix of preferred resources, including energy storage. It is anticipated that these battery storage projects will be less expansive than the natural gas and oil peakers that they are replacing. In March 2020, the CPUC commissioned an expert consultant report to evaluate AB 2514's progress, which report is anticipated in 2022.

AB 2868—California's "Additional" 500 MW Energy Storage Procurement Requirement

AB 2868, signed by California Governor Jerry Brown in 2016, requires PG&E, SCE, and San Diego Gas & Electric (SDG&E) to propose programs and investments for an additional 500 MW of distribution-connected or behind-the-meter ESRs with a useful life of at least 10 years. While there is considerable overlap with the types of resources covered by AB 2514, this new 500 MW requirement excludes transmission-connected resources and is not subject to the 2020 procurement or 2024 installation deadlines and various other AB 2514 program requirements.

Under an April 2017 CPUC decision, each IOU is responsible for developing programs and investments for 166.66 MW of distributed energy storage systems. While the CPUC emphasized that these additional procurement obligations do not alter AB 2514's original targets, for practical purposes AB 2868 will facilitate the interconnection of an additional 500 MW of energy storage to the California grid, along the same general processes of AB 2514. The CPUC's existing limitations on large pumped hydro, electric-vehicle charging, and gas-to-power storage resources remain in place, however. Consistent with other California energy storage initiatives, this CPUC decision continues California's focus on the customer and distribution-connected opportunities for battery energy storage systems.

In March 2018, SDG&E, PG&E, and SCE filed their AB 2868 procurement plans. SDG&E proposed seven storage projects focused on emergency response services (e.g., microgrids for remote fire and police stations) and an incentive program for nonprofit care facilities to install storage. SCE's plan focuses on distribution-connected storage solutions to better integrate distributed renewable resources, and incentivizes up to US$10 million of storage development for low-income multifamily housing. PG&E's AB 2868 procurement plan emphasizes distributed resources to improve grid resilience to wildfires. In July 2019, the CPUC rejected many of the proposed projects, however, and issued guidelines intended to lower the barriers for third parties to participate in the development and ownership of front-of-the-meter storage. Storage must be procured via Requests for Proposals (RFPs) and must meet a "least cost, best fit" criteria. The CPUC also found that "heat pump hot water heating thermal storage is a viable behind the meter option for energy storage" and encouraged the utilities to explore thermal storage, which is consistent with the state's growing "electrify everything" movement.

Under AB 2514, AB 2868, and other procurement efforts, California's IOUs have procured approximately 1,620 MW of new California storage capacity, of which approximately 500 MW are online. California's Community Choice Aggregators (CCAs) are also beginning to procure storage, with East Bay Community Energy, Monterey Bay Community Power, Silicon Valley Clean Energy, and Marin Clean Energy all pursuing a variety of standalone storage or solar plus storage projects to provide capacity or defer distribution and transmission upgrades. Many of the RFOs coming from the California CCAs include a renewables plus storage component and focus on Resource Adequacy procurement.

Several Energy Storage and Distributed Energy Resource Bills Were Signed Over the Last Several Years

Energy storage bills have gained traction in the California Legislature in recent years. In September 2018, California passed SB 1369, a bill that aims to develop hydrogen as a strategy for seasonal energy storage and to flatten spikes in renewable energy production and late-afternoon demand. SB 1369 requires the CPUC, CEC, and California Air Resources Board (CARB) to consider "green electrolytic hydrogen," (i.e., hydrogen produced from electrolysis) as an eligible form of energy storage technology. Regulators are already starting to bank on hydrogen's contribution to meeting California's 100 percent renewables mandate, with a joint CEC/CPUC agency workshop labeling hydrogen fuel cells and storage as a "Zero Carbon Firm" resource to replace existing gas generation. California's SB 700 also extended the state's Self-Generation Incentive Program, described further below.

These efforts in 2018 built upon a very strong 2017 for energy storage in California. Signed in September 2017, SB 338 requires the CPUC and the governing boards of local publicly owned electric utilities to consider how energy storage, energy efficiency strategies, and DERs can help utilities meet peak demand electricity needs while reducing the need for new electricity generation and transmission facilities.

Although California has plenty of renewable energy resources, it experiences a deep drop in solar electricity production in the late afternoon and early evening just as people are returning home from work and causing energy demand to spike (i.e., the "duck curve"). This sudden surge in demand is met currently by gas-fired generation, which can be expensive to run in short bursts and does not advance California's clean energy goals. SB 338 requires utilities to consider how this period of peak demand could be met instead by resources that align more closely with California's climate and renewable energy goals, such as fast-ramping ESRs and efficiency and demand response strategies.

The Assembly passed another storage-oriented bill, AB 546, in September 2017. AB 546 requires all local governments to make available online all permitting applications for behind-the-meter advanced energy storage systems and to accept such applications electronically. The law is meant to reduce the burden and costs on residential customers and prompt greater deployment of customer-sited energy storage systems.

Finally, SB 801 increased the deployment of energy storage and DERs to mitigate potential energy shortages caused by the Aliso Canyon gas leak. SB 801 specifically requires the "local publicly owned electric utility that provides electric service to 250,000 or more customers within the Los Angeles Basin" (i.e., LADWP) to do three things. First, LADWP must share electrical grid data with any persons interested in greater deployment of DERs. Second, SB 801 requires LADWP to undertake load reduction measures by favoring demand response, renewable energy resources, and energy efficiency strategies over simply meeting demand with increased gas-fired generation. Third, LADWP was required to complete a study analyzing the cost-effectiveness and feasibility of deploying 100 MW of energy storage in the Los Angeles Basin (the study suggested it would be cost-effective starting around 2021). SB 801 also required any private utility serving the Los Angeles Basin (e.g., SCE) to deploy at least 20 MW of energy storage "to the extent that doing so is cost-effective and feasible and necessary to meet . . . reliability requirements."

The 2019–2020 legislative session saw additional proposed legislation, but no passage of any targeted energy storage bills. The 2019 legislative session saw the introduction of the "Solar Bill of Rights Act." The introduced version of the bill proposed to solidify a customer's rights to generate and store energy on their own property and prohibit the utility or municipality from enacting any discriminatory fees for doing so. The bill would have also required the CPUC to work with CAISO to facilitate the participation of behind-the-meter resources in the state's wholesale energy market. However, legislators altered the bill so significantly that the current version does not even address energy storage. We expect these issues to be revisited as California continues to encounter public safety power shutoffs to mitigate increased wildfire risk.

California's Self-Generation Incentive Program

California's SGIP was created in 2001 and received a significant regulatory overhaul in the spring of 2017. In addition to doubling the annual surcharge amount collected by utilities, the new funding allocations prioritize the development of distributed ESRs.

SGIP provides financial incentives for installing new qualifying technologies to meet all or a portion of the electric energy needs of a facility. Under the new SGIP regime, available funds exceed US$501 million through 2019, while the incentive itself declines on a block basis at each point that 2 percent of total funds are exhausted. Eighty percent of funds are allocated to energy storage technologies, of which 87 percent are allocated for projects greater than 10 kW in size, and 13 percent are allocated to the existing carve-out for residential energy storage projects less than or equal to 10 kW in size. The remaining 20 percent of funds are available for renewable generation technologies. Any single developer/installer is limited to 20 percent of the available incentive funding for the generation, large energy storage, and residential energy storage categories. While historically SGIP funding has been used for large commercial and industrial projects, a quarter of SGIP funds reserved for energy storage will be reserved for low-income residents, government agencies, educational institutions, nonprofits, and other customers located in areas impacted by environmental concerns. In September 2018, the California Legislature added more than US$800 million in SGIP incentives and extended the program through 2026. One surprising factor, however, was a CPUC report indicating that behind-the-meter energy storage actually *increased* GHG emissions because of insufficient price signals to incentivize charging during periods of peak midday solar generation. The CPUC has since taken steps to resolve this issue in subsequent Proposed Decisions.

In response to California's growing wildfire crisis, in September 2019 the CPUC dedicated US$100 million in SGIP's equity budget toward providing incentives to promote residential and critical infrastructure storage in Tier 2 and Tier 3 high fire threat districts. Up to US$1 per watt-hour in incentives are available to battery storage systems, which could cover almost entirely the cost of a Tesla Powerwall for a residence in a wildfire-prone area.

COLORADO

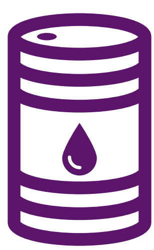
In 2018, Colorado took two steps towards incorporating energy storage into the state's electric grid. First, in March, Governor Hickenlooper signed SB 9 that directed the Colorado Public Utilities Commission to develop rules allowing the installation, interconnection, and use of energy storage systems by utility customers. The legislation establishes that Colorado's electric consumers have a right to install, interconnect, and use energy storage systems without unnecessary restrictions or regulations and without discriminatory rates or fees.

In June 2018, Governor Hickenlooper signed HB 1270 into law, which directs the Colorado Public Utility Commission (PUC) to develop rules for integrating ESRs into the utility planning process. The Colorado PUC adopted these rules in December 2018. Under the revised rules, utilities must evaluate energy storage facilities along with generation facilities in their resource plans and that evaluation must, among others, address the relative costs and benefits of energy storage facilities in avoiding, deferring, or reducing additional investments.

HAWAII

Hawaii's geography encourages the development of renewable energy sources, along with attendant storage capabilities. Hawaii has been an early adopter of energy storage-friendly policies, and the state has several efforts underway to improve energy storage technology.

Over 61 percent of Hawaii's energy is currently derived from imported oil supplies. Starting in 2008, Hawaii and the DOE began collaborating to reduce Hawaii's heavy dependence on imported fossil fuels by transitioning to local, clean, and renewable energy sources. In June 2015, Hawaii became the first state to set a deadline for generating 100 percent renewable electricity when it passed a law directing the state's utilities to generate 100 percent of their electricity sales from renewable energy resources by 2045. Hawaii's 100 percent Renewable Portfolio Standard (RPS) and various other energy independence laws and policies are known as the Hawaii Clean Energy Initiative (HCEI), which includes a public-private partnership between various industry players, the DOE, and Hawaii's Department of Business, Economic Development, and Tourism. Energy storage systems will play a key role in Hawaii's shift toward renewable generation, although the state does not yet have in place any comprehensive tax credit or procurement targets to drive demand.



OVER 61 PERCENT of Hawaii's energy is currently derived from imported oil supplies.

To achieve the HCEI's objectives, Hawaiian Electric (HECO), Maui Electric, and Hawaii Electric Light Company must file joint annual reports with the Hawaii Public Utilities Commission (HPUC) that describe their renewable energy development projects. To facilitate the transition to a more distributed grid, HPUC has announced an expedited process for behind-the-meter storage interconnections. HECO's recent Power Supply Improvement Plan was recently updated to include 150 MW of energy storage. In 2019, HECO negotiated seven solar-plus-storage projects in Oahu, Maui, and Hawaii Island, resulting in contracts for approximately 262 MW of solar and over 1 GW of energy storage. Each of the solar projects are connected to a four-hour battery storage system. These HECO projects are projected to displace 1.2 million barrels of oil each year. In June 2020, HECO announced the winners of its largest-ever renewable procurement. The projects include eight solar-plus-storage projects and one standalone storage project totaling approximately 287 MW of generation and 1.8 gigawatt hour (GWh) of storage in Oahu, three solar-plus-storage projects and one standalone storage project totaling approximately 100 MW of generation and 560 MWh of storage on Maui Island, and two solar-plus-storage projects and one standalone storage project totaling approximately 72 MW of generation and 492 MWh of storage on Hawaii Island. HECO plans to couple grid services and nearly 3 GWh of oncoming stand-alone storage with this influx of solar to replace the two retiring oil-fired power plants on Oahu and Maui.

To further advance battery storage technology, public-private partnerships between the utilities and the Hawaii Natural Energy Institute (HNEI) launched battery energy storage system (BESS) projects throughout the state. Four BESS projects exist presently, and are being used in frequency regulation, peak shifting, voltage support, and power smoothing applications. The long-term objective of HNEI's BESS program is to improve the science of battery storage technology, an important aspect to the development of Hawaii's broader energy scheme.

Significantly, in addition to these public-private partnerships, HPUC has been busy promoting its independent storage agenda. At the start of 2018, HPUC launched "Smart Export," a program directed toward owners of combined rooftop PV–battery storage systems. Owners of these systems will be able to use their battery storage system to store the excess energy that is produced by their rooftop PV system during the day. This stored power will then be used to power their homes at night. Any excess stored electricity that the owners do not use will be exported to the grid, with monetary credits awarded to those who provide their excess generation during nighttime hours.

Energy storage-friendly bills have gained significant momentum in the Hawaii Legislature. There have been nearly a dozen bills on storage incentives or rebates in the last few legislative sessions; however, the legislature has yet to approve any state-specific programs.

MASSACHUSETTS

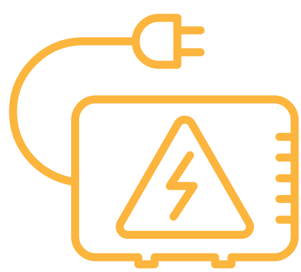
Along with California, Massachusetts has emerged as one of the United States' most active energy storage markets. With one state-sponsored study suggesting that expanding state advanced energy storage programs could capture some US$800 million in system benefits for Massachusetts ratepayers, it is not surprising that Massachusetts considers energy storage developments a "game-changer in the electric sector." Massachusetts continues to see evolution in its energy market as illustrated by Anbaric Development Partners and Commercial Development Co., Inc.'s (Anbaric) announcement that it will convert a former coal power station to a facility that supports offshore wind energy generation with a high-voltage direct current converter and a 400 MW on-site battery storage system.

Energy Storage Initiative

Massachusetts Governor Charlie Baker established the commonwealth's Energy Storage Initiative (ESI) in May 2015 to incentivize energy storage companies to do business in Massachusetts, accelerate early-stage commercial energy storage technologies, expand the market for these technologies, and develop policy recommendations to advance these goals. The ESI has included extensive outreach, including a survey of storage industry stakeholders and workshops to facilitate public input, and produced an in-depth analysis of energy storage issues, *State of Charge*, issued in September 2016.

In August 2016, the Massachusetts Legislature directed Governor Baker's administration to investigate whether it should set an energy storage procurement target for the commonwealth's electric utilities by 2020. Following extensive public input, the Massachusetts Department of Energy Resources (DOER) determined that Massachusetts should set targets for energy storage systems. On 30 June 2017, Governor Baker's administration announced that it has set an "aspirational" 200 MWh energy storage target for electric distribution companies to procure viable and cost-effective energy storage systems by 1 January 2020. In his 30 June announcement, Governor Baker also stated that his administration was evaluating programs to allow energy storage systems to be eligible in future Green Communities grants, which could expand the role of energy storage in complying with the commonwealth's Alternative Portfolio Standard.

Along with California, Massachusetts has emerged as one of the United States' most active energy storage markets.



Clean Peak Energy Standard

Massachusetts is implementing a new program, the Clean Peak Energy Standard, that uses a market mechanism to prompt shifts of clean energy to peak demand periods and reduce energy demand during peak periods. Under this market solution, Massachusetts utilities must procure Clean Peak Energy Certificates of 1.5 percent of annual retail electricity sales (increasing annually to reach 16.5 percent by 2030 and 46.5 percent by 2050).

The program would make energy storage systems that store and discharge energy from energy systems (with four-hour duration and at least 25 percent capacity of the renewable energy system's nameplate capacity as installed or uprated in 2019 or later) eligible to participate in the program. Likewise, existing renewable energy systems would be eligible as well if they are paired with an energy storage system, so long as they are co-located in the same or adjacent parcels with the storage system in a utility's service territory. The storage system must operate primarily to store and discharge renewable energy, which the system can demonstrate by co-locating with a renewable generation resource with a generating capacity of at least 75 percent of the storage system's nameplate capacity, contractual pairing, a charging schedule coincident with periods of typically high renewable energy production, or demonstration via the storage system's interconnection agreement that the storage equipment serves to resolve load flow or power quality concerns associated with intermittent resources.

Massachusetts regulators approved the program in March 2020 to go into effect in June 2020. However, the program went into effect in August 2020. Regulators accepted public comments regarding this guidance through 4 September 2020, meaning that the details of the program remain in flux as of the date of this publication.

Regulators and corporate customers are increasingly interested in the ability of "Clean Peak" standards to match renewable energy with times of peak grid stress where higher-emitting resources are more likely to be dispatched. Similar programs are under consideration in Arizona and California.

MassCEC to Support Innovative Storage Use Cases and Business Models, Safety Development

As part of Massachusetts's broader ESI, the Massachusetts Clean Energy Center (MassCEC) established the Advancing Commonwealth Energy Storage Program. Building on the more than US$9 million, MassCEC has invested in energy storage projects, awarded 26 grants ranging between US$243,000 and US$1,250,000 to projects that have demonstrated a "clear and innovative business model" for a storage project sited in Massachusetts and secured at least 50 percent of the total project budget. The application evaluators also considered whether the applicants plan to collaborate with local utilities in project development. MassCEC is also interested in projects with "nonmonetizable benefits," like those providing flexible response to displace less efficient ramping generation, deferring transmission or distribution investment, or reducing peak capacity requirements. Winning projects must be commissioned within 18 months of contracting with MassCEC.

MassCEC is also coordinating a solicitation for an engineering design consultant for a solar plus storage or energy storage only facility that the Boston Fire Department can use for training and study for safety standards and training purposes.

SMART Program Creates Storage "Adder" for Solar Projects Paired With Storage

Finalized in August 2017, the Solar Massachusetts Renewable Target (SMART) Program further incentivizes energy storage by encouraging solar project developers to pair their solar energy projects with storage. The program creates a financial "adder" above a solar project's base compensation rate for solar projects that co-locate with eligible energy storage projects. The DOER published a Guideline on Energy Storage that better explains the formula used to calculate the SMART program's storage adder and approved the commonwealth's utilities' model tariff provisions to implement the SMART program on 26 September 2018.

One of the obstacles that concerned participants in the SMART program and net metering is the question of which party will control a storage asset's participation in the ISO New England's Forward Capacity Market (FCM). Under Massachusetts Department of Public Utilities (DPU) precedent, utilities hold the rights to bid net-metered solar capacity into ISO-NE's forward capacity market. Although the utilities have not availed themselves of that right to date, the utilities requested that they receive the rights to bid assets compensated under the SMART program, including associated storage assets, into the FCM. Project developers objected, arguing that losing FCM participation rights would undercut efforts to finance solar energy and energy storage projects under the SMART program.

In April 2020, DOER issued emergency regulations extending the reservation period for solar tariff generation units for an additional six months due to the COVID-19 pandemic.

Following a series of meetings, stakeholders, including utilities, solar and storage industry representatives, and Massachusetts DOER, reached a compromise in July 2018. Under this compromise framework, project developers and/or host retail customer-owners would retain FCM rights over energy storage systems that are paired with solar net metering or SMART facilities, with the exception for SMART projects operating under the Alternative On-Bill Credits arrangement in the SMART program rules. Utilities would control FCM rights for those storage facilities, although the project developer or host customer would have the option of buying out the utilities' FCM rights for these projects before approval of interconnection for those facilities. The stakeholders were not able to reach a compromise regarding treatment of behind-the-meter energy storage systems. DPU largely accepted the compromise approach.

In February 2019, DPU further clarified its approach to net metering and FCM participation. DPU confirmed that systems paired with energy storage and that would otherwise be eligible to participate in the net metering program are eligible as long as the operator strictly complies with the rules of the net metering program. For net metering purposes, DPU defined an "energy storage system" as "a commercially available technology that is capable of absorbing energy, storing it for a period of time and thereafter dispatching electricity; provided, however, that an energy storage system shall not be any technology with the ability to produce or generate energy."

In April 2020, DOER issued emergency regulations extending the reservation period for solar tariff generation units for an additional six months due to the COVID-19 pandemic. These regulations also loosen eligibility requirements to maximize benefits under the program (e.g., allowing a single-axis tracker to qualify a system for SMART's Tracker Adder).

Furthermore, DPU clarified that the local utility does not have exclusive title to the energy rights associated with an energy storage system that is paired with a net metering resource. DPU determined that the utility will not own the energy rights associated with Class I net metering resources, with Class II or III net metering resources that the utility has not previously asserted title to, or with a net metering or SMART program facility. However, DPU would grant title to the energy rights associated with Class I facilities that expand to Class II or III under Massachusetts' net metering program. Also, the program would include a "buy-out" option by the facility owner from the utility in cases where the utility owns the energy rights of an energy storage system.

Legislation Proposed to Support Energy Storage

The Massachusetts Legislature has proposed more than two dozen pieces of legislation in recent years to continue supporting energy storage development and deployment across the commonwealth. Some of the notable bills include:

- S.2008 proposes a statewide energy storage deployment goal of 2,000 MW by 2030 and would direct DPU to set another target by 2035;
- S.1977 would direct DOER to establish an incentive program for additional deployment of energy storage systems in Massachusetts;
- H.3622 mandates DOER to create a rebate program for Massachusetts-based companies that install or manufacture energy storage systems;
- H.2884 would remove the date restriction from the definition in "qualified energy storage system" so that systems installed prior to 2019 could participate in the commonwealth's Clean Peak Energy Standard; and
- H.4912 would modify a number of the commonwealth's climate and clean energy programs, including authorizing municipalities to approve energy storage projects that will improve climate resiliency and environmental justice.

Private Efforts for Utility-Scale Storage Deployments

Massachusetts utilities have advanced their own efforts to deploy energy storage projects. For example, Eversource Energy (Eversource) has proposed a series of thermal and battery storage demonstration projects designed to lower peak demand, which will be paid for by a US$21 million energy efficiency surcharge. Opponents have criticized both efforts as presented. Eversource has also filed a general rate case proposing an additional US$100 million of energy storage projects because DOER has not yet detailed its energy storage targets for Massachusetts utilities. The commonwealth's Department of Public Utilities approved two energy storage projects with a total budget of US$65 million as part of the rate case. Eversource and National Grid participate in a demand response program called ConnectedSolutions where residential battery systems can earn incentive payments by allowing Eversource to discharge the battery during periods of high demand.

Separately, Anbaric announced in May 2019 that the companies plan to convert the former coal-fired power plant at Brayton Point in Somerset, Massachusetts, to an offshore wind manufacturing and logistics hub. The facility will also host 400 MW of battery energy storage on the site. Investment in the storage portion of the project alone is expected to total some US$400 million.

NEW JERSEY

In May 2018, New Jersey became the fifth state with an energy storage target and the first within the territory of PJM. The New Jersey Bill, A 3723, signed into law by Governor Phil Murphy, required that the New Jersey Board of Public Utilities (BPU) conduct an energy storage analysis and submit a written report to the governor within one year of enactment. The law required BPU to consult with PJM and other stakeholders in preparing the energy storage analysis. In addition to reviewing how energy storage systems can benefit ratepayers, the analysis must also consider the need for integrating DERs into the electric distribution system. This analysis was finalized on 23 May 2019 and found that pumped hydro and thermal storage technologies are already cost-effective and that the cost of battery storage is dropping rapidly. The report concludes that incentives will be required for prompt deployment of storage pursuant to the law.

The bill also requires BPU to initiate a proceeding to establish a process and mechanism for achieving a goal of 600 MW of energy storage by 2021 and 2,000 MW by 2030. With a 2,000 MW goal, the New Jersey legislation is currently one of the most aggressive energy storage mandates in the country. New Jersey currently has 475 MW of energy storage systems.

On 10 June 2019, the BPU issued a draft Energy Master Plan that set forth a policy vision for achieving 100 percent clean energy by 2050. The plan calls for utilizing storage resources as part of increasing the penetration of DERs throughout the state. Additionally, the plan calls for the development of mechanisms to support the energy storage targets set in the Clean Energy Act by focusing on small capacity projects and pivoting to larger projects as costs decrease and energy storage infrastructure improves. The final draft of the plan reiterates the state's goal of 600 MW of energy storage by 2021 and 2,000 MW by 2030 and states that BPU is preparing a strategy to achieve goals.

The plan notes an Energy Storage Analysis prepared by Rutgers University which concluded that pumped hydroelectric and thermal storage are cost-effective under New Jersey's current energy program, battery storage is not. The plan commits New Jersey to modify its regulatory programs to ensure that battery storage services are fully compensated for system resilience, carbon mitigation, and transmission/distribution system benefits. However, some across the storage industry have raised concerns that New Jersey has not taken enough action to support 600 MW of energy storage deployment by next year.

NEW YORK

New York is following the lead of California, Massachusetts, and other states to spur investment in energy storage technology development and deployment. State regulators have directed utilities to install two storage projects each by 2018, the state has established a funding program, and the legislature has signaled its support for energy storage with legislation that would require the state to set an energy storage procurement goal for 2030. The state is progressing towards its storage goals, with Key Capture Energy installing a battery storage system near Albany, NY in September 2019. A 2019 New York Public Service Commission study concluded that 230 MW of the state's peak generation fleet, or about 6 percent, is ripe for replacement by six-hour duration energy storage systems. By March 2020, there were more than 1,000 MW of storage projects in the queue for distribution utility interconnection and 8,000 MW in the bulk storage queue of the NYISO.

As the state encourages energy storage development, other agencies within New York are developing additional safety standards for energy storage systems. Both the Fire Department of the City of New York (FDNY) and the New York State Energy Research and Development Authority (NYSERDA) are considering safety issues. New York Governor Andrew Cuomo established a roadmap (detailed below) to meet energy storage installation goals by 2030.

Regulatory Mandate for Two Storage Projects by 2018 and 3,000 MW by 2030

To encourage the state's utilities to more quickly deploy energy storage technologies, the New York State Public Service Commission (NYSPSC) used a March 2017 order to direct the state's utilities to "significantly increase the scope and speed of their energy storage endeavors." This order included a mandate requiring each individual utility to deploy and have operating energy storage projects at no fewer than two separate distribution substations or feeders by no later than 31 December 2018. NYSPSC states that the utilities should "strive to perform at least two types of grid functions" with each of the storage projects, such as increasing hosting capacity or peak load reduction, and notes that energy storage projects designed as non-wire alternatives or pilot projects will be considered for compliance with this directive. NYSPSC expects the utilities to meet this mandate using their existing budget authorities and reiterates that any incremental project with an incremental budget increase must be proposed to and approved by the NYSPSC.

In December 2018, the NYSPSC established an energy storage goal of 3,000 MW by 2030 with an interim goal of 1,500 MW by 2025. The New York Legislature codified this goal in a statute passed in July 2019. These targets were based, in part, on an analysis of what it would take to retire vintage combustion turbine peakers in New York City and Long Island by 2025. NYSPSC plans to meet this goal through utility RFPs. Following this approach, Con Edison, Inc. (ConEd) issued an RFP seeking at least 300 MW of energy storage capacity for installation by the end of 2022. Similarly, National Grid and other utilities issued

RFPs for 10 MW or larger energy storage systems in September 2019. By 2020, operators proposed 600 MW across seven storage projects on Long Island. In New York City's Zone J, power plant operators have proposed a total of 1,040 MW energy storage projects. The next round of RFPs under this program is anticipated in the second quarter of 2021.

The NYSPSC approved a program for utilities' dynamic load management (DLM) in September 2020. A Term-DLM project will be a peak shaving project that can be dispatched within 21 hours of advanced notice. An Auto-DLM project would provide peak shaving and reliability services for dispatch within 10 minutes of advanced notice. The agency anticipates that the programs should be operational by 1 May 2021. ConEd expects to issue an RFP for DLM resources towards the end of November 2020.

NYSERDA's Funding Opportunities

NYSERDA has established a series of funding opportunities. The agency announced in April 2019 that it will provide US$280 million in incentives for energy storage deployment. The program will include US$150 million for grid-connected bulk energy storage projects that are 5 MW in capacity or greater and US$130 million for storage projects that are smaller than 5 MW and may be operated as storage alone or paired with on-site power generation. NYSERDA also expects to award US$70 million for initiatives that are likely to help build a self-sustaining energy storage industry. And NYSERDA expects to award another US$53 million in funds from the Regional Greenhouse Gas Initiative for retail and bulk energy storage projects on Long Island.

In April 2017, NYSERDA established, as part of its Clean Energy Fund, a US$15.5 million funding program for energy storage projects. Through the funding program, identified as Program Opportunity Notice 3541, NYSERDA sought proposals for field demonstration projects of "commercial distributed energy storage systems that leverage the flexibility of energy storage to 'stack' two or more value streams by performing multiple functions for retail electric customers, distributed generation, utilities, and the NYISO."

As NYSERDA's storage programs have expanded, it has set up a number of additional funding programs for energy storage, including incentives for bulk storage systems of greater than 5 MWAC for wholesale market energy, ancillary services, and/or capacity services and financing for energy storage projects.

Legislative Action and Roadmap

The New York State Legislature unanimously passed legislation supporting energy storage development by directing the New York State Department of Public Service (NYPSC) to develop an Energy Storage Deployment Program (Deployment Program) to encourage the installation of storage facilities. As part of the Deployment Program, NYPSC must develop a target for storage procurement by 2030, and develop programs to help the state meet that target. Eligible storage technologies include any mechanical, chemical, or thermal process that stores energy generated at one time for use at a later time, including storing thermal energy for direct use in heating or cooling at a later time and that avoids using electricity for such heating or cooling. NYPSC has already ordered utilities to install two distribution-connected energy storage systems by the end of 2018.

Passed by the state Assembly on 17 May and by the state Senate on 19 June 2017, Governor Andrew Cuomo signed the bill on 29 November 2017. With his signature, Governor Cuomo issued a statement asserting that he has some concerns with the legislation's interaction with the state's Reforming the Energy Vision initiative and that he expects to work with the legislature to resolve his concerns with the legislation's fiscal commitments through the state's annual budget negotiations.

To meet the 2030 goal, in June 2018, Governor Cuomo announced the New York State Energy Storage Roadmap (Roadmap). The Roadmap proposes that stakeholders across New York State install 1,500 MW of energy storage capacity by 2025. The New York State Department of Public Service will coordinate solicitation of public comments and a series of technical conferences to finalize a storage installation target by the end of 2018. On 12 September 2018, NYSPSC accepted

the environmental review of the Energy Storage Roadmap as complete.

To implement the Roadmap's goals, Governor Cuomo proposes making US$350 million available for energy storage projects, adding energy storage to the NY-Sun program for solar-plus-storage projects, and additional regulatory and permitting changes to reflect the resilience and environmental benefits of energy storage systems.

Developing Safety Standards for Battery Storage Systems in New York and Beyond

As developers work to increase energy storage's penetration in the New York market, other New York authorities have undertaken a review of the safety standards for battery storage systems, particularly in densely populated areas like New York City. The FDNY, in collaboration with NYSERDA, ConEd, and the National Fire Protection Association (NFPA), is developing a new set of standards for energy storage applications. NYSERDA and ConEd commissioned a report on the fire risks surrounding energy storage systems, which concluded that the risks associated with energy storage systems are manageable. FDNY proposed safety standards for outdoor battery storage systems in April 2019. Separately, the NFPA has established its own safety standard for stationary energy storage systems, NFPA 855.

New York City had only 4.8 MWh of energy storage capacity installed as of the start of 2017, so addressing these safety issues will be critical for growth of the energy storage market in New York, especially for the behind-the-meter residential market. Smart DG Hub, supported by NYSERDA and the City of New York, prepared a set of permitting and interconnection guidelines in April 2018 for outdoor lithium-ion battery storage systems so stakeholders in addition to New York City itself are also working to address energy storage safety questions.

NEVADA

Nevada continues to make advances in promoting energy storage technology within the state. In 2017, the Nevada Legislature passed in SB 204 which directed the Public Utilities Commission of Nevada (PUCN) to investigate whether it was in the public interest for electric utilities to procure energy storage systems, based on several statutory criteria including cost-effectiveness. In 2018, a PUCN commissioned study by the Brattle Group that found a 1,000 MW level of energy storage deployment by 2030 would be cost-effective. The PUCN adopted these findings in December 2018, in PUCN Order No. 34974. In March 2020, the PUCN issued Order No. 44671, which adopts regulations setting biennial energy storage procurement goals for electric utilities. The regulations require electric utilities to include an energy storage plan in their integrated resource plans. The regulation essentially sets a goal for utilities to achieve 1,000 MW of energy storage by incremental 200 MW increases every two years until 31 December 2030. However, as contemplated by SB 204, the targets established by the regulations' goals, not mandates. Nonetheless, by adopting these regulations, Nevada has joined an increasing number of states that are setting energy storage goals.

In the private sector, the PUCN phased out incentives for solar-plus-storage installations in 2019. However, under AB 405, Nevada customers are still guaranteed the right to interconnect solar-plus-storage systems in a “timely manner,” as long those interconnections meet health and safety codes.

In January 2018, NV Energy, the state’s primary investor-owned utility, issued its first RFPs for renewable energy projects including battery energy storage systems. As a result, NV Energy has contracted for six large-scale solar plus battery storage projects with 100 MW of battery energy capacity. The projects, which the PUCN approved in December 2018, are expected to come online by the end of 2021. On 24 June 2019, NV Energy announced three new solar projects totaling 1,200 MW paired with 590 MW of battery storage, which are expected to come online in 2023. The projects will allow NV Energy to run 65 percent of the time during peak summer hours, instead of the 29.9 percent average of Nevada solar plants. It will also assist in meeting Nevada’s newly passed renewable portfolio standard of 50 percent renewable-generation by 2030 and 100 percent by 2050.

Most recently, the Gemini Solar Project received federal approval to proceed with a large solar-plus-storage project north of Las Vegas. Projected to be one of the biggest renewable energy projects globally, the Gemini Solar Project will provide 690 MW of power and 380 MW of battery storage.

OREGON

Legislation: HB 2193

Oregon has followed California in implementing a statewide energy storage mandate with HB 2193, passed in June 2015. The law requires each electric company with 25,000 or more retail customers to procure one or more storage systems with capacity to store at least 5 MWh of energy, with the total capacity procured by each company limited to 1 percent of that company’s 2014 peak load.

In 2017, the Public Utility Commission of Oregon (OPUC) released the guidelines for implementing the legislation, providing details on how the utilities must submit their proposals to meet the state’s energy storage requirements. The guidelines direct Pacific Power and Portland General Electric (PGE), the state’s privacy electricity providers, to submit proposals by January 2018 for qualifying energy storage systems, and public workshops are expected to follow.

OPUC has stated that it is seeking a balanced portfolio of storage projects that serve multiple applications and can defer or eliminate the need for system upgrades. It encouraged the utilities to submit multiple projects that test varying technologies or applications and to use a request for information process to identify suitable vendors.

In 2018, OPUC approved both PGE and Pacific Power's plans for complying with HB 2193. PGE announced that it would spend up to US$100 million to acquire approximately 39 MW of ESRs spread across existing generator sites, distribution sites, and customer sites. In 2018, PGE launched a "smart grid" project in Portland, Hillsboro, and Milwaukie. The project aims to increase decarbonization and to modernize by broadening and enhancing the microgrid system. One means by which to encourage the microgrid concept is by encouraging customers to install energy storage devices, a plan that these three Oregon cities are pursuing in earnest. Storage will play a significant role in Oregon's achievement of its 50 percent renewable energy target by 2040.

Energy Storage Pilot Project

Oregon has also promoted energy storage technologies in connection with its initiatives to foster microgrid technology. In December 2015, the Oregon Department of Energy secured support from Sandia National Laboratories for an energy storage pilot project, granting a total of US$295,000 in state and federal funds to the Eugene Water and Electric Board for its project demonstrating energy storage and microgrid technology. The Grid Edge Demonstration project aims to help Oregon better understand how different energy storage technologies can strengthen long-term grid resiliency. The project uses solar panels, advanced batteries, and smart grid technology to test the capability of microgrids to supply electrical power for crucial infrastructure and public emergency management services.

SOUTH CAROLINA

Energy Freedom Act

South Carolina continues to implement statewide policies to incorporate solar PV and battery storage technologies into its electric grid. Signed into law in 2019, the Energy Freedom Act (EFA) altered state policies that restricted renewable energy growth and created avenues to bolster the energy resilience of South Carolina. While the EFA more broadly focuses on transitioning to an avoided

cost ratemaking methodology, it also specifically highlights battery storage technologies and includes language to incentivize the future use of battery storage and expand the opportunity for further investment in the industry. While the EFA may not set an aggressive strategy to incorporate battery storage into its grid, the passage of the bill indicates a reshaping of the South Carolina clean energy market with a lean towards the incorporation of battery storage in the near future.

TEXAS

Texas has also become a leader in defining the role that energy storage can play in enhancing grid reliability and efficiency. Texas' unique dynamic of regulated and unregulated electric utilities, its own independent system operator (the Electric Reliability Council of Texas (ERCOT)), and a climate conducive to wind and solar generation have made Texas an ideal test site for energy storage technology. Texas projects have included utility-scale projects as well as microgrid and community storage developments, including Oncor's advanced microgrid incorporating 25 kW of community energy storage systems; E.On's Texas Waves 20 MW battery storage project collocated with wind generation facilities; Austin Energy's aggregated fleet of customer-sited energy storage; and Duke Energy's Notrees 36 MW storage project that operates as an ancillary services resource. Luminant, a subsidiary of Vistra Energy, began operating a 10 MW storage facility collocated at Luminant's existing 180 MW Upton 2 solar project on 31 December 2018. Since then, Broad Reach Power has commenced construction of two 100 MW batteries, which are slated to come online in 2021. Key Capture has also announced that it will finish a 100 MW battery and two 50 MW plants by early 2021, demonstrating the race to develop the largest systems in the state.

Legislative Efforts

In 2011, the Texas Legislature passed SB 943 clarifying that energy storage facilities intended to be used to sell energy or ancillary services in ERCOT's competitive markets are "generation assets" that must register with the Public Utility Commission of Texas (PUCT). This legislation allowed energy storage facilities to interconnect, to obtain transmission service, and to participate in ERCOT's wholesale energy market, although the "generator" label raises questions on whether such assets can be owned by regulated transmission providers (discussed in greater detail, below).

In 2009 and 2013, Texas created the New Technology Implementation

Grant (NTIG) fund as part of the Texas Emissions Reduction Plan. The NTIG fund allows grants for storage projects co-located with renewable energy generating facilities in air quality-affected counties. To date, three utility-scale energy storage projects have received grants through the NTIG fund.

On 1 September 2019, Senate Bill 1012 went into effect in an effort to make clear that electric cooperatives and municipally-owned utilities can own or operate batteries without having to register as a power generation company. Sections 35.151 and 35.152 of the Texas Utilities Code currently require owners and operators of energy storage equipment to register even though cooperatives and municipally-owned utilities cannot qualify under the Section 11.003(14) definition of power generation company. The PUCT had previously urged the legislature to provide clarity in this area, expressing concern that the existing language may lead to the unintended inference that cooperatives and municipally-owned utilities cannot own or operate battery storage equipment.

PUCT Rules

In connection with Texas legislative efforts, the PUCT has enacted several rules easing the ability of ESRs to participate in ERCOT's wholesale electricity markets. Under PUCT Substantive Rule 25.192, wholesale energy storage is exempt from transmission service rates and wholesale storage load is excluded from ERCOT's four coincident peak demand calculations. PUCT Substantive Rule 25.501(m) defines "wholesale storage" as something that occurs when electricity is used to charge a storage facility, the storage facility is separately metered from all other facilities including auxiliary facilities, and energy from the electricity is stored in the storage facility and subsequently regenerated and sold at wholesale as energy or ancillary services. Rule 25.501(m) further provides that wholesale storage is deemed to be wholesale load, and ERCOT is to settle it accordingly using the nodal energy price at the electrical bus that connects the storage facility to the transmission system (or if the storage facility is connected at distribution voltage, the nodal price of the nearest electrical bus that connects to the transmission system). The rule also provides that wholesale storage is not subject to retail tariffs, rates, and charges or fees assessed in conjunction with the retail purchase of electricity. Collectively, these rules are thought to help ease storage into ERCOT's markets.

The Role of Storage as Distribution in Texas

In February 2018, the PUCT opened a new proceeding titled "Rulemaking to Address the Use of Non-Traditional Technologies in Electric Delivery Service" to consider whether ESRs can be owned by transmission and distribution utilities and serve as a replacement for traditional transmission and distribution infrastructure (February 2018 Rulemaking). The February 2018 Rulemaking stems from an application submitted by the transmission and distribution utility—AEP Texas—in

September 2016, in which AEP Texas proposed to construct two ESRs in lieu of otherwise necessary traditional distribution upgrades and to include the battery storage facilities in rate base. In connection with AEP Texas's request, which was highly contested, the PUCT considered: (1) whether ESRs would constitute "generation" or "competitive energy services," such that they could not be owned and operated by a regulated transmission utility; (2) whether battery storage facilities used to provide distribution-related services could be considered "distribution" and therefore be included in rate base; and (3) how the energy consumed by the battery storage facilities should be viewed under Texas law. Ultimately, the PUCT dismissed AEP Texas's request without prejudice, finding that it lacked sufficient information to make a final determination. As part of the dismissal, however, the PUCT instituted the February 2018 Rulemaking to "develop a framework within which the [PUCT] can consider a broader range of technologies and study the potential impacts to the [energy markets] in ERCOT."

In October 2018, the PUCT issued a request for comments on the February 2018 Rulemaking. The PUCT's request primarily focuses on the issues raised during the AEP Texas proceeding, namely whether transmission and distribution utilities can own and rate base ESRs that replace traditional transmission and distribution upgrades and that are used to support reliability. In November 2018, interested parties, including AEP Texas, submitted comments in response to the PUCT's request for comments. In early 2019, the PUCT announced it would defer further action until the conclusion of the 86th Legislature. In May 2019, Governor Greg Abbot signed Texas Senate Bill 1012, which allows municipally-owned utilities and electric cooperatives to own electric energy storage equipment without having to register as a "power generation company" in Texas. It remains to be seen whether Texas will take further steps to enable utility ownership of ESRs.

VIRGINIA

Virginia Clean Economy Act

In April 2020, Governor Ralph Northam signed the Virginia Clean Energy Act (VCEA) into law, redirecting the standards and goals of the Commonwealth of Virginia towards a more renewable-centric scheme. Of its primary goals, the VCEA establishes a mandatory renewable portfolio standards program, replacing its voluntary program and proposing to be 100 percent carbon-free by 2050. The VCEA also establishes energy efficiency standards and advances goals in solar and distributed generation, including requiring Virginia's largest energy companies to construct or acquire more than 3.1 GW of energy storage capacity by 2035. With the passage of the VCEA, Virginia becomes the seventh state to establish a clear energy storage capacity goal.

The VCEA prompted the creation and development of a regulatory scheme to achieve its energy storage goals. By January 2021, the VCEA requires the

In May 2019, Washington enacted SB 5116 which mandates that the state obtain 100 percent of its electricity from non-fossil sources by 2045.

Virginia State Corporation Commission (SCC) to adopt regulations to achieve the successful deployment of energy storage in the Commonwealth by setting interim targets and updating existing utility planning and procurement rules. The SCC initiated administrative proceedings on 29 June 2020 to incorporate public comment into its rulemaking process. In September 2020, the SCC released a set of proposed rules after receiving input from various stakeholders. Statewide, those rules propose that Virginia's utilities generate or acquire 300 MW of storage capacity by December 2025 and 3.1 GW by 2035. At the time of the drafting of this publication, the rulemaking process is still underway with anticipated completion in November 2020.

WASHINGTON

The state of Washington took a big step toward its grid modernization efforts in 2013 with the launch of the state's Department of Commerce's Clean Energy Fund. The Clean Energy Fund has provided two rounds of funding since its inception. In the first round, which took place from 2013 through 2015, the state awarded US$14.5 million in matching "smart grid" grants for developing energy storage technologies, including: (1) US$3.2 million to Avista Corp. (Avista) for the testing of utility-scale battery developed by UniEnergy Technologies; (2) US$3.8 million to Puget Sound Energy to launch a utility-scale battery; and (3) US$7.3 million to Snohomish County Public Utility District (SnoPUD) for experimental projects using a 500-kilowatt hour (kWh) lithium-ion battery and a 6.4 MWh energy utility technology flow battery. In a requirement unique to Washington, eligible energy storage projects were required to incorporate a common technology standard to integrate energy storage system performance with grid operations (the Modular Energy Storage Architecture or MESA).

Following the success of the first round, the Clean Energy Fund launched additional grid modernization grants for projects from 2015 through 2017. One grantee, the Pacific Northwest National Laboratory, received funding to develop an integrated electrical system, a collaborative project with both the University of Washington and Washington State University. The other grants went toward projects proposed by Demand Energy Networks, Inc. and by Battery Informatics, Inc. to improve battery technologies and energy storage systems. Avista and SnoPUD received additional funding (US$3.5 million each), as well. Avista has developed a microgrid using solar panels and battery storage that employs a "sharing" concept, whereby grid users share power equitably among themselves as a means of cutting down on usage inefficiencies. In addition to its partnerships with private companies, SnoPUD is working to create the Arlington Microgrid and Clean Energy Technology Center, which will use battery storage and microgrid technology to power one of its offices during grid outages and will educate the public on these areas of technological development.

On the regulatory side, the Washington Utilities and Transportation Commission (UTC) issued a draft policy statement in spring 2017 recognizing that energy storage is a "key enabling technology" for decarbonizing the Washington grid. Washington's IOUs were directed to use an integrated resource planning process to analyze energy storage options before committing to other resources, like gas-fired peakers. The UTC also made clear that it would apply ordinary cost recovery mechanisms to IOU acquisition of ESRs.

In May 2019, Washington enacted SB 5116 which mandates that the state obtain 100 percent of its electricity from non-fossil sources by 2045. The law requires utilities to consider energy storage in its resource planning. Public-private partnerships have made significant efforts towards this transition already. Puget Sound Energy (PSE) launched the Glacier Battery Storage Project, which involved the installation of a 4.4 MWh lithium-ion battery system to serve as a backup power source for the Glacier project area, a zone made up of an assortment of businesses and residences. PSE and the Washington State Department of Commerce (WADOC) contributed US$7.4 million and US$3.8 million to the project, respectively. Similarly, Avista and the WADOC commenced a 3.2 MWh large-scale battery storage project used to research and further develop the battery technology. Avista and WADOC each contributed around US$3 million to the project. Governor Jay Inslee has signaled that the government will continue to support the development of energy storage projects in the state which has resulted in significant recent developments. Energy Northwest, a Washington-based energy provider, has started building a combined 5 MW solar-plus-storage facility, which will be located in Richland, Washington. The Clean Energy Fund awarded half of the US$6.5 million required to build the facility.

INDEPENDENT SYSTEM OPERATORS AND REGIONAL TRANSMISSION OPERATORS

RTOs/ISOs are public utilities that operate (but do not own) the transmission grid in large parts of the United States and Canada. In addition to ensuring that open-access transmission services are provided on a non-discriminatory basis, RTOs/ISOs plan transmission expansion projects and manage the interconnection process for new generation assets. RTOs/ISOs also operate the markets for energy, ancillary services, and, in some cases, capacity, and through stakeholder processes, they develop market rule proposals for FERC consideration. RTOs/ISOs maintain tariffs and various other agreements that are "on file" with FERC, as well as manuals and other documents that set forth the rules governing the markets and services offered by the RTO/ISO.

The California Independent System Operator (CAISO)

CAISO is one of the oldest ISOs in the nation, responsible for managing about 80 percent of California's electricity flow. In collaboration with CEC and CPUC, CAISO has been at the forefront of considering ways to incorporate ESRs into California's wholesale electricity market. Starting around 2011, CAISO began several stakeholder initiatives to address the ramping issues caused by California's abundant solar resources and the retirement of nuclear and once-through-cooling gas-fired generation assets. Energy storage technologies have played a big role in shaping the policy decisions in CAISO's Flexible Resource Adequacy requirements, its Flexible Ramping Product, and Phases 1 and 2 of the Flexible Resource Adequacy Criteria and Must-Offer Obligation proceedings.

In 2014, CAISO (in collaboration with the CPUC and CEC) began its energy storage and distributed energy resources (ESDER) initiative. In 2016, CAISO updated its tariff to allow storage providers to self-manage their state-of-charge and energy limits, and to directly submit their state-of-charge status into the day-ahead market to better reflect the actual conditions of the storage resource. In Phase 2 of the ESDER process, CAISO evaluated tariff modifications to enhance demand response rules, provide more certainty on station power and multiple-use applications, and provide better modeling, all of which are aimed to better capture storage's contribution toward grid reliability. In September 2018, the CAISO Board of Governors approved ESDER Phase 3, which proposed a load shift product for behind-the-meter energy storage under the proxy demand response (PDR) participation model. The initial product will allow access to day-ahead and real-time energy markets for both load curtailment and load consumption by assigning behind-the-meter storage resources two distinct resource identities. CAISO has designed the PDR product to help address over-supply, store negatively priced energy during times of abundant renewable energy, and deliver that energy back to the grid during the late-afternoon ramp.

ESDER Phase 4 is ongoing and focuses on, among other things, two ways to better integrate energy storage into the wholesale CAISO markets: first, implementing an "end of hour" state-of-charge parameter for the non-generator resource mode; and second, streamlining market participation agreements for non-generator resource participants. The latter development, in particular, should better recognize the unique attributes of energy storage that do not fit the mold of traditional generator and load resources. CAISO anticipates approving ESDER Phase 4 by the end of 2020 with full ESDER Phase 4 implementation in Fall 2021.

CAISO has also been a leader among the RTOs/ISOs in aggregating DERs, similar to what FERC Order No. 2222 proposes to do nationwide. In 2016, CAISO adopted tariff provisions creating a new market participant category called a distributed energy resource provider (DER Provider). A DER Provider is a market participant that aggregates one or more small distribution-connected energy resources (like energy storage systems) totaling at least 0.5 MW. CAISO's DER aggregation program recognizes the difficulty in incorporating small distribution-connected resources into a market run by the transmission-level operator, and stakeholders are continuing to work toward improving communication at the transmission-distribution interface (i.e., at substations). Initial participants using the new DER aggregation tariff have had some success converting storage and electric vehicle resources from demand response resources to energy resources. It is worth noting that FERC's Energy Storage NOPR was modeled on some of the concepts in the CAISO tariff, although it is CAISO's view that ISO and RTO retain the flexibility to enact policies that best represent the interests of their varied stakeholders and the region they serve. As FERC Order No. 2222 develops, expect to see RTOs/ISOs learning from the CAISO experience.

PJM Interconnection

PJM is an RTO/ISO that operates the high-voltage transmission grid in all or parts of the Mid-Atlantic states, the Midwest, and central Appalachia, as well as markets for capacity, energy, and ancillary services. While pumped storage hydropower resources have long participated in PJM's markets, PJM has also integrated over 300 MW of battery and flywheel storage facilities, and it has more than 4,500 MW of ESR capacity in its interconnection queue. PJM is also evaluating the use of other technologies, including thermal storage and vehicle-to-grid integration, to further stabilize and improve the PJM grid.

The Role of Storage in PJM

ESRs may inject energy onto the PJM grid as "generation" to participate in PJM's wholesale markets under PJM's market rules. Storage resources acting as generation may then provide energy, capacity, or ancillary services provided they meet the standard parameters for participating in each market. In 2012, following the issuance of Order No. 755, PJM revised its frequency regulation market rules to differentiate between traditional generators with limited ramp rates (Regulation A resources) and energy-limited resources that have faster ramp rates, such as batteries (Regulation D resources). To date, and with the exception of pumped hydropower, the majority of ESRs operating as generators in PJM participate exclusively in PJM's frequency regulation market as Regulation D resources.

ESRs may also participate as behind-the-meter "demand response"—a program that compensates retail customers for reducing their electric load when called upon by PJM. However, under PJM's market rules, these resources are generally unable to also participate in PJM's other markets. This is due in large part to PJM's existing demand response framework, which effectively prohibits demand response resources from also injecting energy onto the PJM grid.

PJM and its stakeholders also are considering market reforms that could permit ESRs to be treated as transmission assets and to be integrated into PJM's regional transmission planning. PJM is developing a proposal, expected in late 2020, that would guide the consideration of ESRs as transmission assets designed to address reliability planning criteria, reduce transmission congestion, or meet public policy objectives. One key issue is whether such resources could act as transmission assets during some periods while acting as market participants during other periods, along with the complex issues surrounding cost recovery and cost allocation that dual-use would entail.

Changes to PJM's Frequency Regulation Market

Following the establishment in December 2015 of a cap on the amount of Regulation D (RegD) resources that could be dispatched during certain orders, and the implementation in January 2017 of operational changes to the RegD signal, the Energy Storage Association filed a complaint with FERC (April 2017 Complaint). The Energy Storage Association argued that these changes to the regulation market, and specifically to the RegD signal, were unduly discriminatory against limited-energy resources. PJM subsequently filed proposed market rule revisions in October 2017 to further revise the means through which RegA and RegD resources would be dispatched and compensated (October 2017 Filing). Various intervening stakeholders protested PJM's October 2017 Filing, claiming that the majority of the changes would have a disproportionate impact on storage resources were inconsistent with FERC Order No. 755 and would limit the participation of ESRs in PJM's regulation market.

In March 2018, FERC issued companion orders on the April 2017 Complaint and October 2017 Filing. FERC agreed with protesting intervenors and rejected the October 2017 Filing, finding that it failed to satisfy Order No. 755's requirement that storage resources participating in regulation markets be treated in a non-discriminatory manner. Similarly, FERC established hearing and settlement procedures to address concerns in the April 2017 Complaint about the changes to the PJM regulation market since 2015. In March 2020, FERC approved a contested settlement resolving outstanding issues in the proceedings, pursuant to which. "Affected Battery Owners" will participate in the Regulation market under specific terms and conditions agreed to in the settlement. In the settlement as approved, PJM has also indicated its intention to file additional "enhancements" to the regulation market in the future which, according to PJM, may include elimination of the RegD signal and use of a single, technology agnostic, regulation signal.

PJM's Response to Order No. 841 and Section 206 Proceeding

In October 2019, FERC conditionally approved PJM's Order No. 841 compliance filing, finding that PJM's proposal generally enables electric storage resources to provide all services they are capable of providing while also recognizing the unique physical and operational characteristics of storage resources. FERC also approved PJM's subsequent compliance filing in July 2020, subject to limited further compliance.

However, concurrently with its October 2019 order, FERC also opened an investigation to determine whether PJM's existing 10-hour runtime requirement for ESR participation in PJM's capacity market should be changed. FERC issued an order in April 2020 delaying action in the proceeding, however, in order to allow PJM and its stakeholders to explore the use of a methodology called "effective load-carrying capability" to set the capacity value of limited-duration resources, including ESRs. FERC also expanded the proceeding to evaluate the capability not only of ESRs, but of all capacity resources. Finally, FERC ordered PJM to submit by 30 October 2020, tariff modifications setting forth proposed methodologies for assessing resources' capacity capability or a brief addressing its current methodologies, including the 10-hour runtime requirement.

Electric Reliability Council of Texas

ERCOT is the ISO responsible for operating the transmission grid and energy-only wholesale markets in the state of Texas. Apart from a few interconnections to reach generating plants near bordering states, ERCOT's authority is entirely intrastate. This limitation makes ERCOT unique among ISOs, as its rates for wholesale power are exempt from FERC jurisdiction and are instead subject to the jurisdiction of the PUCT. Regarding the integration of energy storage, ERCOT's efforts are guided by state legislative mandates and the PUCT's regulatory directives. The PUCT in particular has enacted a number of rules intended to facilitate greater participation by ESRs in the ERCOT wholesale electricity markets.

In conjunction with the PUCT's efforts, ERCOT has revised its Nodal Protocols, which govern wholesale market participation. Nodal Protocol Revision Request 461 implemented the process for settling ESRs in the energy markets. ESRs carry "Wholesale Storage Load," which in Texas is limited to the following technologies: batteries, flywheels, compressed air energy storage, pumped hydro-power, electrochemical capacitors, and thermal energy storage. Other Texas-specific definitions state the parameters that ESRs must meet to participate in the Regulation Services markets and outline the make-whole calculation processes for ESRs.

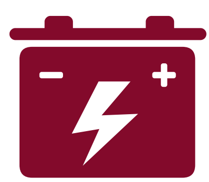
The Midcontinent Independent System Operator

MISO operates the transmission grid across 15 states in the Midwest and South Central United States, as well as the Canadian province of Manitoba, and operates energy and ancillary services markets and a voluntary capacity market. For years, MISO has operated pumped hydroelectric storage resources, and in recent years it has begun to operate a limited amount of battery storage. MISO's interconnection queue, however, demonstrates strong interest in ESRs, including approximately 4,200 MW of active requests associated with standalone ESRs and a large number of hybrid resources, as well.

ESRs as Transmission Assets

In August 2020, FERC conditionally accepted a filing submitted by MISO allowing for the consideration and selection of ESRs as solutions to identified transmission planning needs in the MISO Transmission Expansion Plan. The first-of-its-kind filing establishes a category of ESRs in the MISO Tariff called a "storage facility as a transmission-only asset" (SATOA) that will be evaluated along with more conventional transmission projects and, if selected and brought online, would receive cost-based compensation using existing cost recovery methods. Under the new framework, MISO would assert operational control over the SATOA in order to operate the transmission system, while the SATOA owner would retain responsibility for managing its state of charge. Any net revenues from buying and selling energy to do so would pass through a designated market participant and serve to decrease the SATOA's revenue requirement. However, SATOAs will not otherwise be permitted to participate in MISO markets or in its voluntary annual capacity auctions.

Enhanced AGC Signals for East Ramping Resources



In January 2020, FERC issued an order accepting MISO's proposed market rule changes to make better use in its frequency regulation markets of resources, including ESRs, that are capable of faster ramping than conventional resources. MISO proposed to enhance its automated generation control (AGC) system by instituting a second AGC signal for resources capable of achieving a ramp rate of 80 MW per minute, meeting certain performance criteria, and being deployed for longer than 20 minutes. According to MISO, this will allow such fast ramping resources to respond quickly to the second AGC signal before backing down once more slowly ramping resources are able to take over - preserving fast ramping resources while freeing more conventional resources to maintain energy deployment levels. Ultimately, MISO believes that adjusting its AGC logic in this way could improve its system's reliability and efficiency, while also creating a more flexible system that integrates more variable energy resources.

The New York Independent System Operator

NYISO operates the transmission grid and manages the competitive wholesale markets for electric energy, ancillary services, and capacity in New York. NYISO has long worked to accommodate ESRs, and it continues to consider, plan and implement additional measures to aid in the full participation of ESRs in its markets.

ESRs and Distributed Energy Resource Aggregations

In addition to its compliance with Order No. 841, FERC also accepted in January 2020 market rule changes proposed by NYISO that create a participation model for aggregations of DERs, including ESRs. In this model, an aggregation of resources can participate as a single entity in NYISO's wholesale energy, ancillary services, and capacity markets with a minimum offer of 100 kW, provided each individual resource

is electrically connected to the same transmission node. Further, under NYISO's rules, all wholesale market participants, including such aggregations, will benefit from a "dual participation" model in which they can simultaneously offer into the wholesale markets while also providing energy and services to local distribution utilities and host load. Together, the ability to include ESRs in an aggregation of resources, and for those aggregations to provide services in both the wholesale and retail markets, promise to open up new revenue streams for ESRs, which in turn could foster the creation of new business models and drive innovation.

Planning for Colocated Storage Resources

As part of a broader effort to address issues faced by hybrid resources, NYISO and its stakeholders have worked throughout 2020 to finalize a proposal for a participation model accommodating co-located storage resources (CSRs), and anticipate submitting market rule changes to FERC in late 2020 or early 2021. NYISO describes CSRs as a combination of an intermittent generation resource and ESRs that are co-located, in front of the meter, and behind the same point of interconnection. The anticipated market rule changes are expected to require each unit within a CSR to submit separate bids and to be settled independently, but NYISO would use a scheduling constraint to determine feasible energy and reserve schedules for units within the CSR. NYISO is likely to propose that units within CSRs have separate interconnection agreements, though developers would be able to submit one single interconnection request.

ISO New England

ISO-NE operates the transmission grid in the six New England states, and manages markets for wholesale energy, capacity, and ancillary services. ISO-NE long has operated pumped hydroelectric storage, and about 20 MW of grid-scale battery storage has been interconnected since 2015. According to ISO-NE, another 2,265 MW of standalone ESR projects have joined its interconnection queue, and a number of other projects in the queue incorporate ESRs.

In the years before Order No. 841, ISO-NE already had begun making changes to its markets to accommodate ESRs. For example, ISO-NE introduced in 2015 an "energy-neutral" dispatch signal to help integrate ESRs (and particularly batteries and flywheels) into its regulation market, and in 2018 it fully integrated demand response resources (including ESRs) into its energy and reserve markets.

Shortly after FERC issued Order No. 841, ISO-NE also submitted and received FERC approval to put in place a market design capable of integrating ESRs into the New England markets.

Under the framework laid out in the tariff, which generally has preserved its Order No. 841 compliance filing, ESRs fall into one of two categories based on their physical characteristics: Continuous Storage Facilities, which can transition easily and quickly between charging and discharging (e.g., batteries), and Binary Storage Facilities, which cannot (e.g., pumped hydroelectric storage). Further, ESRs must register both as generation and load assets to manage the facility's injection and withdrawal of energy, respectively, and Continuous Storage Facilities also must register as regulation assets to provide services in that market.

ISO-NE has continued to amend its market rules to account for the capabilities that ESRs can offer to its grid and markets. For example, in September 2019, FERC accepted tariff revisions submitted by ISO-NE that provide audit procedures to establish the capability of ESRs to provide reactive power to support the grid, as well as to ensure that ESRs receive compensation when they do supply reactive power.

Southwest Power Pool

SPP operates the transmission grid over a large part of the central United States, including all or part of 14 states, and manages the SPP Integrated Marketplace, the region's energy and ancillary services market. According to SPP, its interconnection queue included in mid-2020 nearly 9 GW of requests from ESRs, most of which are paired with solar projects and would not be operational until 2023 or later.

There are a limited number of ESRs currently operating within the SPP region, including both pumped hydroelectric and battery storage, all of which act only as generators. While not as mature a market for ESRs as other RTOs/ISOs, SPP convened an Electric Storage Resources Steering Committee to work (in parallel with its Order No. 841 compliance efforts) to develop and recommend policies and procedures that would facilitate the integration of ESRs into the SPP transmission grid and markets. The Committee is working to educate SPP stakeholders and propose solutions to issues identified in a white paper commissioned by the SPP Board of Directors in mid-2019 and released by SPP staff in January 2020. These include technical, tariff, and cost allocation aspects in a wide variety of areas, such as the integration of ESRs into transmission planning processes, the challenge of ESRs serving multiple functional roles, modeling hybrid resources, resource adequacy accreditation for ESRs, and more. The Committee's recommendations are expected in January 2021.

While largely approved by FERC, SPP's tariff revisions complying with Order No. 841 will take effect later than those in other regions. In December 2019, SPP renewed an earlier request that the Commission grant a delay on the effective date of these provisions to accommodate SPP's timeline for launching a new system to manage its settlements process and subsequent software development. The Commission granted SPP's request and its tariff Order No. 841 revisions now will likely become effective in August 2021.

DEVELOPMENT ISSUES FOR ENERGY STORAGE

Financing and Monetizing Energy Storage Projects

Installed capacity of energy storage is expected to reach 2.6 GW by 2022 in the United States, and this expansion will drive the need for sophisticated and cost-effective project financing. Unlocking sources of financing across the sector will be vitally important in realizing the monetary and societal benefits of energy storage.

Fundamentals and Challenges of Energy Storage Financing

Financing for energy storage projects shares some of the same fundamentals as solar and wind. Investors and lenders seek projects that combine contracted long-term revenue streams produced by technology that is well proven and reliable with contractual performance assured by creditworthy counterparties or financial instruments such as performance insurance.

Beyond these fundamental similarities, however, energy storage projects are inherently more complex than solar and wind and typically face several additional types of challenges in seeking financing.

First, in contrast to the relatively simple metrics of renewable generation projects (e.g., kWh multiplied by PPA prices over time), energy storage projects may generate economic benefits through one or more different value streams. In preparing an economic model to support financing, the sponsor must clearly define the use cases for the project and link them to concrete and reliable future net revenue streams. Where a project benefit is in the form of cost savings, such as demand charge reduction, quantifying, and monetizing that benefit will be a key step. Energy storage may also entail multiple concurrent benefits, such as providing grid-support services while at the same time serving as on-site energy supply. Deriving solid financial returns for these value streams—and ensuring that any potential conflicts and management issues among them are addressed—will be a necessary prerequisite to financing.

Second, compared to generation projects, energy storage technology requires significantly more active and sophisticated management over the life of the project, and has greater potential for change of use, than solar or wind. Operations and asset management for solar projects or wind with a PPA are straightforward, well understood, and contractually defined. The project generally needs to deliver energy on a steady stream over time, addressing only sporadic and usually immaterial operations and maintenance issues. The developer may promise the offtaker that the project will achieve specified availability or output guarantees, with liquidated damages to flow from the failure to do so. A storage project, however, typically requires dynamic ongoing management and software controls to address changing circumstances and objectives. Where grid services are provided, those controls must mesh with the utility framework and tariffs and meet applicable communications, technology, and contractual requirements. Performance guarantees concerning system availability, round-trip efficiency, capacity, or ramp rate will be constrained by the operating characteristics of the integrated energy storage system as well as by the use case(s) envisioned by the offtaker. Realizing the revenue streams on which financing will be based thus means facing additional ongoing uncertainties compared to traditional renewable energy generation projects.

Finally, the market and regulatory contexts for energy storage are rapidly evolving and may be unpredictable. Value streams may quickly change or dry up, as seen in PJM's decision to substantially decrease the Regulation D payment rates for frequency regulation services from energy storage. Utilities and state public utilities commissions in several major jurisdictions are in the process of reforming energy distribution and customer platforms. Interconnection rules, siting requirements, and market participation procedures are changing. New storage technologies are emerging, and software systems and transaction regimes such as blockchain are creating major new capabilities. All of these areas of change create potential risks and opportunities that must be assessed in considering financing terms.

Given these inherent complexities, the cost of capital for storage project finance has yet to see substantial reductions. On the risk-return continuum, equity has, understandably, been the dominant source of financing for the nascent energy storage industry to date. Tax equity (in solar and storage configurations) and debt are beginning to take on more active roles, however, as revenue streams, risk factors, and contract structures are becoming more clearly defined.

Current Long-Term Energy Storage Agreement Structures

While many energy storage projects have been developed as merchant facilities, particularly in ERCOT, MISO, and PJM, numerous energy storage projects have successfully entered into long-term contracts for offtake of the storage resource or to assist in financing. Although these long-term agreements are sometimes referred to casually as "energy storage PPAs," this omnibus term is a bit of a misnomer because several forms of agreement have been developed to take advantage of energy storage systems as both generator and load (i.e., discharging and charging). While each form of energy storage agreement has its own peculiar features, several forms of agreement generally in use are summarized below.

Energy Storage Tolling Agreement (Tolling Agreement)

California utilities pioneered the use of Tolling Agreements in connection with their procurement of utility-scale storage projects that are interconnected to the transmission or distribution system. Under a Tolling Agreement, the energy storage system developer is responsible for obtaining site control, permits, interconnection rights, equipment, and construction contracts and achieving agreed-upon milestones, usually including a target commercial operation date and a guaranteed commercial operation date. The buyer (here, the utility) pays for the electricity used to charge the battery storage system and receives the right to charge or discharge the system for energy and ancillary services, all within specified operating parameters. The storage provider receives a capacity payment, which is adjusted for the storage system's availability and round-trip efficiency, and a variable O&M payment for energy dispatched from the system. The buyer will usually insist on the right to dispatch the system to provide ancillary services like frequency regulation, usually without any additional compensation to the seller beyond the capacity and variable O&M payments. Because the buyer owns the energy stored in the battery, Tolling Agreements often prohibit the developer's use of the storage system for station service—a condition that requires the developer to enter into a retail service contract for the system's non-storage load. Tolling Agreements are similar in many respects to gas tolling agreements, with "round-trip efficiency" being analogous to a heat rate and "availability" generally performing the same function under both types of agreement.

Capacity Services Agreement (CSA)

Under a CSA, the developer is responsible for developing, installing, and operating the energy storage system and charges the system at its own expense. The offtaker (usually a utility) pays a capacity charge for the system, subject to adjustment for availability, and uses the storage system's capacity attributes to satisfy the offtaker's resource adequacy (RA) requirements. The CSA typically allows the developer to market certain products from the energy storage system to third parties, as long as the delivery of such products does not interfere with the developer's obligation to deliver RA to the offtaker as and when required by the CSA. To enable the offtaking utility to monitor the multiple uses to which a given energy storage system is being put, the utility may require the developer to give notice of the market services being offered. CSAs are used for utility-scale energy storage projects that will be interconnected with the transmission or distribution systems.

Demand Response Energy Storage Agreement (DRESA)

If a developer provides on-site, behind-the-meter storage to a number of customers, it may be able to aggregate the storage capabilities of those customers and enter into a DRESA. A DRESA between a local utility and an energy storage system developer allows utilities to compensate an energy storage system developer for providing the utility with energy storage system capacity and demand response energy storage ancillary services.

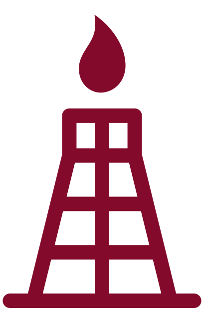
The DRESA is typically supported by agreements with each storage site host that also obligate the developer to provide on-site energy management services. Under these customer agreements, each customer contractually allows the developer to make the storage systems available to reduce demand at the direction of the utility offtaker. The developer then enters into a long-term DRESA with a utility buyer under which the developer agrees to cause its customers to switch to energy storage as, and for the duration, requested by the utility, again subject to the operating parameters of the aggregate system. During this period, the developer's customers will rely on energy discharged from the storage system instead of electricity from the utility, thus reducing load on the grid. A DRESA may allow demand response assets to be deployed without capital expenditures by either the storage system host or the local utility, which provides advantages to several stakeholders at once.

Hybrid Agreements

Energy storage systems can be combined with other renewable generators, most commonly solar systems but occasionally wind generators. For tax and other reasons, the storage system and generator are usually located at the same site and, in the case of solar and other ITC-qualified facilities, more than 75 percent of the power used to charge and the storage system must be charged from the renewable generator rather than from the grid until the five-year recapture period has ended. In that case, the cost of the storage system should qualify for the ITC. There is less certainty regarding whether storing power generated by a PTC-qualified facility prior to sale of the power to a third party would limit or prevent the seller's ability to claim the PTC. For more information, please see the general discussion about Federal Tax Incentives, above.

A hybrid agreement may be structured so that the developer is paid a per-MWh purchase price based on the electricity delivered at the interconnection point, in which case the developer will manage and pay for the charging and discharging of the energy storage system to maximize the revenue from the hybrid facility's output. If this structure is used, the developer does not receive a capacity payment and the offtaker does not control the charging or discharging of the storage system.

Other hybrid agreements are structured so that they more closely resemble tolling agreements. The offtaker purchases solar or wind energy on a per-MWh basis, and the developer delivers the generation to the offtaker and/or charges the storage system in accordance with the offtaker's charging instructions. The offtaker decides when to discharge the system. The agreement should include mechanisms for determining the amount of energy sold and stored, round-trip efficiency, the amount of energy discharged, and the total amount of electricity delivered to the delivery point. In addition to a per-MWh payment for energy produced by the generator, the developer receives a capacity payment that is typically adjusted to reflect the actual availability, capacity, and round-trip efficiency of the storage system. The stored electricity is owned by the utility and thus is not available for station service. The developer's availability, capacity, and round-trip efficiency guarantees will affect the capacity payment received by the developer and will be tied to the system's operating parameters. The operating parameters are in turn structured to account for the system's expected use case(s).



Energy storage agreements usually include a fairly detailed exhibit setting out the system's operating parameters. Among other things, the exhibit would define the maximum number of full cycles per day, the maximum number of full cycles per year, maximum daily discharge, maximum annual discharge, and maximum partial discharges, as well as procedures for issuing, accepting, and executing discharge instructions or default charging/discharging strategies. These provisions are especially important in a Tolling Agreement or any other contract in which the buyer has the right to charge and dispatch the facility. If the storage system is operated within the agreed-upon operating parameters, the storage provider is required to meet the capacity, availability, and round-trip efficiency standards set forth in the agreement. On the other hand, if the system is operated outside its agreed-upon parameters, the developer may have the right to refuse a dispatch instruction or a contractual defense to damages or price adjustments imposed due to deficient performance. Careful consideration of the system's operating parameters are very important, as experience in the PJM and MISO teaches that tariff or rule changes that change the way a storage system operates in the market can adversely affect the system's performance and may also limit warranty claims under the storage system's procurement contracts.

The operating parameters set out in the energy storage agreement should also take into account the offtaker's expected use case(s) for the storage system. For example, if the system is being used to store peak solar generation for discharge during the evening hours, the determination of whether the number of full cycles conforms to what is allowed in the operating parameters will be fairly straightforward. If the offtaker plans to use the system to address multiple use cases, it may be more challenging to reconcile the system's actual use with the operating parameters. The uses case(s) may also change during the term of the agreement when new rules are adopted or new services are recognized, in which case the parties may want to include a process that allows the offtaker to implement new use cases, either by making appropriate adjustments to operating parameters or translating the new use case into existing parameters.

Behind-the-Meter Projects

In states like Hawaii, California, and New York, energy storage systems have been installed on the customer's side of the meter, allowing the customer to charge the system in off-peak hours and then discharge it during peak hours. These systems can be dispatched in response to demand response price signals to reduce the customer's usage of peak power or to shave peaks and thus reduce peak demand charges. The agreement between the developer and its customer may take the form of a third-party PPA, particularly if the storage system is combined with a solar installation, with payments to the developer based on electricity delivered to the customer. Another type of agreement shares the savings that the customer achieves because it is able to shave its peak demand (and thus its peak demand charges). To date, such agreements exist primarily in states that offer one or more unique market conditions, such as high retail electricity prices, time of use rates that allow charging at off-peak prices and discharging at on-peak prices, market design such as peak demand charges in California or demand response markets in New York, and incentive programs such as California's SGIP. Developers and utilities are continuing to create new forms of financeable agreements applicable to their fast-growing sectors, similar to where solar PV market players were 10 years ago. A brief review of the most common behind-the-meter storage financing agreements available follows.

Operating Leases

An operating lease is an arrangement whereby the owner of an energy storage system grants the host the right to use the system in exchange for a monthly fee that covers the rental of the energy storage system and (in most instances) its operation and maintenance fees, software access fees, installation costs, permitting costs, and sales and property

taxes. The energy storage company, acting as the lessor, uses third-party financing to purchase the energy storage asset; therefore, it is essential that the lease provides for the owner's ability to assign the lease to its financing party.

During the lease period, which is usually 10 years from its commercial operation date (although terms as short as three years have been used), often with the option to extend the term for an additional 10 years subject to the particular lease terms, the energy storage system remains the property of the owner/lessor who will operate, manage, repair, and maintain it. The owner/lessor provides a long-term (again, often for 10 years) limited equipment warranty. The value proposition for the storage system typically will focus on reducing high time of use electricity rates or demand charges and providing backup power to the host/lessee in the event of grid outages. In most cases, the host/lessee will be granted an option to purchase the energy storage system before the lease terminates for its fair market value.

Concurrently, the energy storage system owner/lessor may operate the energy storage system to provide supporting services to the electrical grid, offering potential additional revenues from such activities. This operating lease model is used widely today by leaders in the energy storage market.

Demand Charge Shared Savings Agreements

Similar to the Energy Savings Performance Contract structure used for energy efficiency projects, a Demand Charge Shared Savings Agreement (DCSSA) between a host and a third-party energy storage system owner or operator allows the host to enjoy lower energy consumption costs due to reduced demand charges achieved by discharging the energy storage system during peak hours and by performing energy arbitrage by drawing power during off-peak periods. With the DCSSA, the third-party financiers rely on an allocated portion of the energy cost savings from the reduced tariff-specific demand charges that will be distributed by the host to the project financing providers. The most significant advantage to the host is access to the energy cost-reducing third-party asset with zero upfront capital expenditure on the host's part. Under the DCSSA, the host is provided energy storage-related services on a storage-as-a-service basis. Several companies, including Stem, Advanced Microgrid Solutions, and Green Charge Networks utilize this model in their contractual arrangements with third-party C&I hosts.

Project Financing Risk Identification and Management

Energy storage agreements share many of the issues typical of any long-term PPA, such as force majeure, defaults, collateral assignment, and dispute resolution. Given the complexities of energy storage, however, project financing must effectively address a number of categories of risks associated with new technology, business management, market and regulatory evolution, and credit profiles.

Change in Law and Regulatory Risk

One of the most difficult issues in an energy storage agreement is allocating change in law risk. In California especially, utilities will often procure energy storage so that they can meet AB 2514 targets or other procurement mandates, as well as satisfy RA requirements. If, after the agreement is signed, there is a change in the laws or tariffs governing the targets, RA qualifications, or other key operational features or attributes of the energy storage facility, which party bears the risk of that change?

Developers prefer to shift the risk to the offtaker, arguing that the procuring utility is in the best position to manage changes in the laws, rules, and tariffs governing energy storage systems and how they count in meeting procurement targets or satisfying RA. A utility will often resist a full assumption of this risk, arguing that the small risk of an adverse change in law is better borne by the developer than the ratepayers. Developers, for their part, prefer to avoid provisions that merely excuse its performance and give it a right to terminate in the event the law changes, as such language would increase the risk that the energy storage system will end up as a merchant plant, thus making it difficult to finance the system. Force majeure clauses are not adequate to the task of addressing this issue, and agreements need to address change of law risk allocation head-on.

Not surprisingly, compromises are developing along the same lines as the change of law provisions affecting RPS compliance provisions in renewable energy PPAs. In some instances, utilities will agree to accept the risk of a change in law. In others, the parties will agree to allocate the risk such that the developer bears compliance costs up to a certain point, after which the utility may decide whether it wants to incur additional costs to cause the system to comply with the new law. From the developer's standpoint, the important outcome is that the utility cannot treat as a default the failure to comply with the new law after the cost threshold, if any, is reached, nor can it refuse to continue to receive and pay for the contracted energy storage services specified in the agreement.

Technology Risk

Energy storage agreements usually include a fairly detailed exhibit setting out the system's operating parameters. These provisions are especially important in a tolling agreement or any other contract in which a third party has the right to dispatch the facility. If the storage system is operated within the agreed-upon operating parameters, the storage provider is required to meet the availability and round-trip efficiency standards set forth in the agreement. On the other hand, if the offtaker calls for the system to be operated outside its agreed-upon parameters, the developer will have a contractual defense to any damages or price adjustments imposed due to non-performance. Experience in the PJM and MISO teach that tariff or rule changes that change the way a storage system operates can adversely affect the system's performance and may also limit warranty claims under the storage system's procurement contracts.

The operating parameters set out in the long-term agreement should also take into account the offtaker's expected use case(s) for the energy storage system. For example, if the system is being used to store peak solar generation for discharge during the evening hours, the determination of whether the number of full cycles conforms to what is allowed in the operating parameters will be fairly straightforward. If the offtaker plans to use the system to address multiple use cases, it may be more difficult to reconcile the system's actual use with the operating parameters. The uses case(s) may also change during the term of the agreement when new rules are adopted or new services are recognized, in which case the parties may want to include a process that allows the offtaker to implement new uses cases but ties each new case to the system's operating parameters.

Behind the representations on operational performance is a concern that the energy storage technology will not perform as expected in the future and/or that operation and maintenance costs will be greater than anticipated. Today, lithium-ion batteries are perceived as safe and bankable. Because successful project financings depend on long-term manufacturer warranties backed by creditworthy entities, it is normal today for equipment manufacturers to stand behind their products with warranties that range from several to 10 years. Performance ratings and performance guarantees are increasingly being used to mitigate the technology risk posed by the lack of long-term performance energy storage system-related data.

Safety risks have also been a major area of focus. The DOE and Underwriters Laboratories are continuing to work on establishing codes and standards for avoiding project technology failures and resulting health and property impacts and financial liabilities. As in the solar

> Energy storage must be effectively managed and controlled to interface with generation sources and the grid.

industry, the practice of conducting bankability studies to support financing is taking root for storage. Performed by technical consultants with access to extensive databases of prior projects, such bankability studies can provide detailed due diligence on the project technology, reliability, and durability; the manufacturer and supply chain; and operations, asset management, software controls, and maintenance going forward.

Asset Management Risk

As discussed above, energy storage must be effectively managed and controlled to interface with generation sources and the grid. Software technology uncertainties and the need to rely on sophisticated asset management services over time create additional risks that must be assessed.

Credit Risk

There is always a risk of default by the borrower, who may be unable to service the debt as contracted. Prospective lenders are cautious about entering the market, as it is still considered immature despite the fact that several lenders have been actively supporting certain developers deploying energy storage systems in the past few years. Credit risk assessment for energy storage also extends beyond the project counter-parties to third parties, such as equipment manufacturers, software suppliers, and asset managers that the project may be relying on for warranties, guarantees, and operational effectiveness going forward. Insurance covering project assets and operations, as well as performance insurance supporting performance guarantees, often will be required.

Tax Credit Allocation

Because Congress may at some point enact an investment tax credit for standalone energy storage, energy storage agreements with utilities sometimes include a provision that is intended to prevent the developer from reaping a windfall if the project is able to secure tax equity financing after the agreement is signed. In general, these provisions contemplate that if the developer is able to secure tax equity financing, it must share the economic benefit of that financing with the utility, often in the form of a price reduction. Apart from the commercial question of whether the developer is willing to share a potential future tax credit, several issues should be considered in evaluating these provisions. Some clauses imply that the developer bears all of the transaction costs of securing the “economic benefit” produced by the tax credit (even though it receives only a share of that benefit), rather than defining the economic benefit as net of transaction costs. Such provisions often require the developer to secure the benefit of any tax credit or other incentive that becomes available after the agreement is signed, but the developer may prefer to reserve the ability to exercise its reasonable discretion in deciding whether the effort required to secure the shared economic benefit will justify the costs to the developer. The definition of "economic benefit" should also be carefully reviewed to assess its assumptions about what a tax credit for storage would look like if Congress were to pass one. The provision should also specify when the price adjustment triggered by the benefit will take effect. Finally, given that a storage tax credit would be a new incentive, the clause should include language requiring the parties to cooperate reasonably in working through the details of implementing the sharing arrangement.

Build Transfer Agreements

For various reasons, including the desire to rate base assets, utilities may prefer to acquire and own the energy storage system. As in the wind and solar industries, utilities may sometimes seek to accomplish this result by entering into a Build Transfer Agreement or similar arrangement (BTA). Under a BTA, the storage system developer takes the development risk of putting the storage project together. Depending upon the needs of the parties, the BTA may cause the developer to transfer the project assets to the utility at a relatively early stage pursuant to an asset purchase agreement, after which the developer will install the system in accordance with an engineering, procurement, and construction (EPC) contract (see below) or other construction arrangement. Alternatively, the BTA may cause the developer to transfer the system to the utility only when the system has achieved substantial completion. In the second scenario, the BTA needs to include a "notice to proceed" mechanism that functions as a financial closing, allowing the parties to resolve all issues pertaining to title, permits, interconnection, equipment procurement, and other matters as conditions to proceeding with the procurement and installation of the system. The utility is then obliged to pay for and purchase the storage asset, barring a material adverse effect such as a casualty that destroys the system.

Trends Toward Standardization

A number of participants in the energy storage sector are actively working towards standardized approaches to risk management and contractual allocation. End-to-end contractual solutions are being developed by companies whose business models require ease of obtaining finance. Such efforts are being augmented by a number of non-governmental organizations, such as the Energy Storage Association and Rocky Mountain Institute's Business Renewables Center, that provide forums for finance experts to work with developers in overcoming common obstacles and streamlining financing processes. Sandia National Labs, the National Renewable Energy Laboratories, and others are working under DOE programs seeking ways to reduce barriers for new lenders and to create trusted analytical benchmarks to assess and price risk in more systematic ways. Further rapid advances in these areas should be expected in the next few years, helping to open the spigot of financing for the energy storage sector.

In recent years, the energy storage industry has seen several significant and positive changes including equipment cost reductions, regulatory incentives, viable market structures, and proliferation of long-term agreements. Each of these makes deploying energy storage systems more viable than ever before. As access to project financing is still an issue for many developers, however, it is encouraging to see project finance lenders taking a greater interest in financing large-scale energy storage projects in the United States and abroad.

In addition to more lenders entering the market, one of the main potential catalysts for the expedited deployment of additional energy storage systems would be Congress passing an ITC for standalone storage facilities. With or without the ITC, the fundamental economics and optimism in the energy storage industry indicate that energy storage can flourish in the coming years and the project financiers will have ample opportunities to make a significant contribution to this process. Each of the groups of participants in the storage ecosystem—sponsors, developers, financiers, and utilities—must work to streamline and standardize structures and contracts. The overarching commonality with solar and wind is that energy storage offers massive potential economic benefits that could be unlocked as these parties work on more effective approaches to financing. The question is not whether but when and how rapidly the sector can realize the kind of progress seen to date in renewable generation.

EPC Agreements

EPC stands for engineering, procurement, and construction. This means that the EPC contractor undertakes to provide a complete project solution, including all engineering design, equipment selection and purchasing, subcontracting, installation, construction, performance testing and guarantees, and warranty. Energy storage system developers can use EPC agreements to accomplish two main goals: first, to clearly and concisely state the risks and obligations of the designer, the equipment suppliers, the contractor, and the owner in a way that provides a foundation for a successful project, and second, to cover the main risk points in a way that attracts project financing from the lenders.

Most EPC agreements are turnkey agreements, meaning that the owner is relying on the contractor to design, construct, test, commission, and hand over a fully completed and functional plant. Having a single point of responsibility is, for most owners, the primary advantage of EPC contracts over other project delivery options. An EPC contractor, who is at once

Most EPC agreements are turnkey agreements, meaning that the owner is relying on the contractor to design, construct, test, commission, and hand over a fully completed and functional plant.

the designer, specification writer, and builder, can make changes on the fly that the traditional design-bid-build format does not easily allow. Project lenders have historically preferred EPC contracts that aggressively shift as much risk as possible from the owner to the EPC contractor and thereby provide comprehensive "wrapped" project guarantees from a financially responsible counterparty.

The EPC model seeks to take advantage of the specialized expertise of the contractor-engineer to provide an integrated approach to the planning, design, execution, and performance of the project. In the energy storage market, many project developers and owners are using contracting structures that fall short of the fully wrapped EPC solution. This is in part due to the scarcity of EPC contractors, and partially due to a search for cost savings in unbundling the equipment design, supply, and performance, from the actual on-site civil work and equipment installation. Energy storage integrators typically offer this type of contract structure, which leaves the project sponsor with the important task of minding the interface points between the integrator and the on-site contractor. For this structure to work well, both the integrator and the constructor contracts need to clearly delineate responsibilities upon delivery of the equipment, at which point the contractor assumes responsibility, and upon mechanical completion, at which point the integrator commences commissioning. The risk of expensive finger-pointing contests can be reduced with well thought out processes for the contractor to accept and certify equipment is undamaged at delivery and for the integrator to accept mechanical completion has been achieved without qualification. For the balance of this section, we will use the term "EPC Contractor" for both where an owner hires a single entity and where it chooses to hire multiple contractors (i.e., an integrator and installer) under coordinated contracts.

Several key EPC risk points apply particularly to the energy storage market.

Performance Guarantees

One of the primary objectives for the owner is for the contractual structure to require the EPC contractor or contractors to deliver a project is to ensure that the project as constructed meets the owner's performance objectives. Project lenders want assurances that at the completion of the project, these expectations are met, as proven through performance testing and backed by performance liquidated damages. With respect to energy storage projects, the performance tests may include round-trip efficiency, overall capacity, speed of charge and discharge, and a demonstration of control system performance through a series of test case scenarios. The contract should directly and explicitly set forth the testing procedures, standards, methods, uncertainty principles, and consequences of an adverse test result. The selected test cases need to reflect the use cases underlying the economic pro forma for the project and the offtake revenue assumptions. In some cases, the testing and guarantees can be flexible to accommodate future changes in the operation of the system, for example by the use of energy throughput as a variable underlying the calculation of the guaranteed system capacity. This can require some complicated financial modeling on the owner and lender side to assure that the guarantee and resulting liquidated damages are adequate to protect the project's expected economic performance. For other projects where the use case is fixed (once-a-day cycling, for example), the guarantee may require augmentation at the point where the system capacity falls below expectations, in lieu of liquidated damages.

EPC contractors will generally support well-conceived performance guarantees that focus on objective equipment performance metrics but may be reluctant to agree to arrangements that unreasonably transfer commercial market risk to the contractor through excessive large liquidated damages or overly long terms. Negotiation of appropriate warranties from a commercial standpoint is a balance between what is technically expected and achievable and appropriately respecting the risks and rewards associated with project development as opposed to EPC contracting.

Performance Guarantee Damages

Both the owner and the contractor will suffer consequences if an energy storage system fails the performance tests. One of the most closely negotiated aspects of the EPC contract is the amount of liquidated damages and what additional remedies the owner may have in this circumstance. Contractors typically seek a cap on liability with respect to performance liquidated damages. Agreement on a cap is typically based on a percentage of the contract price. Owners must, of course, carefully consider the extent to which such a cap may leave them with an underperforming resource and no remedy for the adverse economic impacts such as failing to live up to a PPA.

Many EPC contracts will require the contractor to both pay the owner liquidated damages at an agreed daily rate *and* cure the performance shortfall. This "make good" obligation is often triggered only if the facility fails to reach a specified minimum level of performance. Contractors will typically resist a requirement that certain minimum performance levels be achieved no matter what.

Equipment Procurement Issues

It is not unusual for the cost to purchase specialized equipment, such as a particular type of battery or inverter, to comprise a major percentage of an EPC contract price. Given this, it is imperative for the EPC contract to include all necessary and appropriate equipment purchase and sale terms, including, among others: delivery, title transfer, risk of loss, warranties, and intellectual property issues. These issues are heightened when dealing with new and potentially immature energy storage technologies.

Warranties

Project owners and lenders may require a "full wrap" warranty from the EPC, making it responsible for all defects in design, equipment, and performance. Alternatively, an EPC may offer a cost advantage for an "unwrapped" warranty where the warranties applicable to equipment, and even subcontractor work, are simply passed through to the owner for direct enforcement. Issues to negotiate include the term of the warranty, warranty exclusions, warranty claim process and restrictions, and the application of extended warranties for corrective work.

Intellectual Property

The design of an energy storage system and its software programs will incorporate proprietary processes and equipment configurations developed by parties who should be concerned about protecting their important knowledge from theft, misappropriation, or loss of the exclusive right to such proprietary knowledge. Intellectual Property (IP) rights may be addressed in the EPC contract or may be the subject of a separate agreement. These provisions can be relatively simple or quite complex, depending on the size of the storage source, the type of batteries, the control technology to be used, and the extent of the contractor's design obligations (for instance, collocating the storage system with a renewable generator). A good general rule is that each party to an EPC agreement (and its respective design consultants and subcontractors) retains ownership of its respective pre-existing and non-project-specific IP and grants a nonexclusive limited license for use of such IP to other parties only to the extent necessary to complete the project, or in the case of the owner, to operate and maintain the plant upon completion.

Contract Payment Terms

Although the contract price is often one of the first material terms to be negotiated by the parties to any EPC contract, the pricing mechanisms under such contracts can be complex. The two main pricing mechanisms are "fixed lump sum" and "cost plus." Each has many variations.

Owners may prefer to enter into fixed lump-sum contracts whenever possible in order to provide reasonable certainty of the owner's maximum exposure. Often, if the project is subject to third-party financing, the lenders insist on the EPC contract being performed for a fixed contract price. The point of this arrangement is that the contractor largely bears the risk of cost overruns but also gets the benefit of any cost savings, including through subcontractor and supplier discounts. Pricing is particularly dynamic in the battery storage industry, where the cost of lithium-ion technology is projected to continue to drop.

Cost-plus pricing arrangements may be used where: (1) there remains significant uncertainty as to the scope of the project at the time the parties enter into the EPC contract, either because the design remains at an early stage or for other reasons; (2) the owner wants to avoid payment of contingencies unless such costs are actually incurred; and/or (3) the contractor is unwilling to commit to a fixed contract price due to uncertainty or the complexity of the project.

Other Key EPC Terms: Limitations of Liability, Indemnity, and Termination

Owners almost universally prefer not to cap the contractor's liability under the contract; however, few EPC contractors will, as a commercial matter, enter into an EPC contract that leaves them exposed to unlimited liability. Therefore, in many cases the owner will agree to cap the contractor's overall liability to a specific amount—commonly, a percentage of the contract price, and most often 100 percent.

Owners will typically negotiate to exclude certain provisions of the contract or categories of liability from the applicability of the contractor's overall liability cap, such as for personal injury, death, or third-party property damage. Generally, such liabilities should be fully or substantially covered by a policy of

insurance, such as third-party personal injury or damage to real and tangible property. Other exclusions commonly sought by owners are exclusions related to the contractor's gross negligence, willful or intentional misconduct, violations of applicable law and permits, and IP infringement liability.

An indemnity is an obligation by one party to protect another party against loss or damage. Most EPC contracts contain several indemnity provisions. Some of the most common are for loss or damage incurred by the indemnified persons (usually the owner and related entities) related to personal injury, property damage, breach of contract, liens arising from nonperformance, contamination and other environmental issues, or for tort claims. In most states, indemnity obligations are limited by state-law "Anti-Indemnification Statutes" that invalidate a clause in a construction contract that purports to indemnify a party for its sole negligence, and in many cases, prohibit indemnification to the extent that claims arise out of that party's comparative negligence.

Most EPC contracts allow one or both parties to terminate the contract as a consequence of certain specified breaches, acts, or omissions of the other party (i.e., a termination for cause). Typical events of default giving rise to the right to terminate include insolvency, unauthorized assignment, change in control for either party, failure to maintain financial security, failure to make payment, failure to achieve milestones, and breach of any material contract provision. In addition, owners often require a right to terminate the EPC contract for reasons unrelated to the contractor's performance under the contract. This is usually referred to as a "termination for convenience" or "T for C." Normally, such entitlements are resisted strongly by contractors and are not reciprocal due primarily to the difficulty and cost associated with replacing a contractor during the project.

Avoiding Disputes in Battery Storage Supply Agreements

As the industry has matured, contracts for the supply of battery storage plants have come to better define and allocate the major risks inherent to large-scale battery purchases. In particular, suppliers, purchasers and their attorneys have become increasingly adept at clearly describing precisely how a particular plant is warranted to perform, the conditions and use case for operation, and the available remedies for breach. That said, recent disputes over older contracts from the mid-2000s are still instructive as to some of the areas where more careful and explicit drafting to eliminate ambiguities can avoid expensive arbitration or litigation. This section addresses some of these key considerations.

Exclusivity of Remedies and Limitation of Liability

In EPC and other battery plant supply contracts, it is common practice for the plant supplier to provide at least two remedies for defective equipment or performance—a warranty and a performance guarantee. Generally speaking, the warranty defines the supplier's obligations to repair, replace, or upgrade the plant as required for the plant to perform at a certain specified minimum level for the duration of the warranty period. The performance guarantee defines the supplier's promise to pay a liquidated damages amount to compensate the purchaser or developer for lost revenue resulting from the plant's failure to discharge (or charge) as promised—up to a defined cap. Issues around each of these provisions are discussed in greater detail below.

As a foundational matter, however, contracts should clearly define the extent to which the parties intend these two basic remedy provisions to be the exclusive remedies for plant underperformance or equipment failures. If the contract language leaves any doubt that the supplier's warranty and performance guarantee (and any other liquidated damages provisions) are the sole and exclusive remedies for underperforming or defective equipment, a creative lawyer can (and will) seek additional measures of damages. A purchaser may seek, for example, the difference in value between a performing system and the defective or underperforming system supplied in addition to warranty damages or performance liquidated damages. Such additional damages could come as a surprise to the supplier.

This goal can be achieved by defining the interaction between the warranty and the performance guarantee. Typically, if the warranty is breached by equipment failure or underperformance, then the supplier is obligated to repair or replace the defective components until the plant once again performs up to an agreed upon minimum threshold. Until such repairs or replacements are performed, the performance guarantee kicks in, obligating the supplier to pay performance liquidated damages to compensate the purchaser for lost revenue resulting from the performance problems (again, subject to an agreed-upon liquidated damages cap).

Specification Definition

In the mid-2000s, parties sometimes defined the promised performance of a battery storage system in ways that left important aspects of performance open to interpretation. While industry participants have become savvier about specifically defining promised operation requirements, care should be taken to ensure that the promised specifications are not open to more than one interpretation. The input of a technical professional is recommended. Some issues that have arisen:

Application vs. "Nameplate" Specifications

In the past, some contracts incorporated both application-based requirements and "nameplate" requirements into the contractually promised specifications. For an example, the supply contract may have promised a system that could respond to a particular dispatch signal, while at the same time promising a nameplate maximum energy output and energy storage rating (kW/kWh). Including both specifications could raise issues about whether the system must be able to perform under nameplate specifications for a substantial duration even if the specified dispatch signal rarely required charging or discharging at maximum nameplate power.

Vague "Nameplate" Specifications

Older contracts sometimes stated "nameplate" requirements as two simple figures: the maximum (dis)charge power rating over the maximum energy storage capacity. Such specifications were at least arguably unclear as to whether the system would have to charge or discharge at the maximum rated power for the entire duration of a full charge or discharge cycle, or for some shorter period of time.

Regulatory Framework

As noted above in the section discussing financing risks, a major risk of any energy storage project is regulatory volatility. In the battery supply context, unforeseen regulatory changes can not only upend the parties' pricing or revenue expectations, but can also result in unexpected changes to the operating demands. An example would PJM's modifications to regulation frequency dispatch signals in 2016 that dramatically increased battery throughput. A careful delineation of anticipated operating parameters and use cases discussed below may obviate the need to carefully delineate in a supply contract the parties' expectations concerning the regulatory environment. That said, if a unilateral regulatory or operational change by a utility or RTO could result in modified operating parameters and increased degradation, the parties should explicitly allocate that risk.

Warranty

The warranty in a battery storage supply agreement expresses the parties' intent concerning the allocation of the risk of equipment failure or underperformance. If it is defined as an exclusive remedy, it defines the extent of the supplier's post-acceptance obligations and the limits of the purchaser's primary remedies. As such:

- The warranty should clearly define (or incorporate by reference) the guaranteed minimum performance of the system with specificity. At a minimum, the warranty should state or incorporate the required charge and discharge power, the duration that charge or discharge at maximum power can be sustained, the minimum energy storage capacity of the system, and the number of years such minimum performance is guaranteed.

- Currently deployed battery technologies will suffer capacity degradation over time. Such degradation will accelerate under higher temperatures and increased charging and discharging demands. Typically, the warranty limitations will include a maximum battery cycle or power throughput limit, in addition to a limit defined by a number of years. It is important to carefully define the limit unambiguously. For instance, a reference to maximum charge or discharge cycles should spell out what the parties mean by cycle.
- The warranty should avoid wholesale incorporation of complex design or manufacturing specifications that could allow a party to argue that the system failed to perform in ways not relevant to basic system performance or revenue. As an example, the warranty should not implicitly promise that the system will perform within a specified module temperature range that can be found in a specifications appendix unless the supplier intended to warrant this feature.
- The warranty should be clear about the use case or cases covered by the warranty. For instance, if the supplier only intends to warrant the plant for use for solar plant storage in a specific market, the warranty should be limited to that use and explicitly exclude coverage for alternative uses or for different geographic markets that may involve different demands on the batteries under different operating conditions.
- While the warranty should not wholesale incorporate voluminous specifications, it should clarify the precise operating parameters for the system for the warranty to be in effect. Using the solar storage example, the warranty should state explicitly the charge and discharge demands that the system was designed to accommodate. The parties should state whether use of the system in a more demanding application that will lead to increased battery temperatures or accelerated degradation void the warranty.
- The parties should carefully consider whether the warranty should also include standard limitations, such as the effect of a force majeure event on the supplier's warranty obligations. To the extent the effect of a force majeure event only temporarily affects performance, the parties should consider how long the warranty obligations may be suspended before terminating entirely.

Performance Guarantee

In negotiating and drafting any performance guarantee or other liquidated damages provision designed to mitigate the purchaser's exposure to financial losses resulting from equipment defects or plant underperformance, additional issues should be explicitly addressed in the contract language:

- At least in the United States, state law imposes limits on liquidated damages (LDs). Typically, for a liquidated damages provision to be enforceable, two requirements must be met: (1) the amount of actual damages had to have been uncertain or difficult to calculate at the time the contract was executed; and (2) the liquidated damages have to have a reasonable relationship to or be a reasonable estimate of actual damages. Applying this rule, the parties should draft liquidated damages calculations that incorporate market pricing variables to at least approximate actual lost revenue resulting from plant defects or deficient battery performance.
- The parties should ensure the contract incorporates a mechanism to allow both parties access to all data required to calculate performance LDs. The supplier may lack access to actual battery performance or market revenue data absent an agreement by the purchaser to supply the data on which their LD calculations are based.
- Since no battery supplier is willing to provide an insurance policy to the purchaser against all possible revenue losses due to battery or plant issues, the parties should agree to an unambiguous cap on liquidated damages liability and specify whether the cap is also applicable to warranty damages.

- The parties should carefully consider whether they intend for the purchaser to recover any other damages in addition to performance liquidated damages. If performance LDs indeed approximate actual lost revenue, a supplier may insist that they are the exclusive remedy for periods of poor system performance.

Dispute Resolution Provisions

Virtually all battery supply contracts now incorporate mandatory arbitration provisions selecting arbitration as the exclusive means to resolve irreconcilable disputes. Rather than simply incorporating boilerplate arbitration or choice of law clauses, the parties should carefully consider a few important issues that could have significant effects on the ultimate resolution of disputes:

Arbitration Clause

While arbitration can be less expensive and faster than litigation in court, arbitration awards are largely unappealable, even when they contravene applicable law or misstate the evidence. For this reason, parties should carefully consider provisions that require the arbitrator to have particular technical qualifications or experience, or provisions that limit the authority of the arbitrator. To the extent that the arbitration clause limits the arbitrator's authority to enter an award consistent with particular law or a particular evidentiary standard, it may provide limited appeal options that would not otherwise exist.

Choice of Law

Before simply choosing the law of the state of a party's headquarters or the plant location as the law to govern any possible dispute, the parties should examine the chosen forum's treatment of key issues, such as the interpretation of force majeure provisions, liquidated damages standards, and the enforcement of arbitration awards.

Attorney Fees

Most contracts will provide for a prevailing party to recover its reasonable attorney fees and expenses in litigating or arbitrating a dispute under the agreement. The contract should explicitly state whether such fees can be in addition to the overall contractual liability limits (typically the contract price), or whether attorney fees can be assessed over and above the contractual liability cap.

Force Majeure Clauses

All battery storage contracts incorporate force majeure clauses. These clauses terminate or suspend a party's performance in the event of an unforeseen event that makes renders performance impossible. It is a misimpression that all force majeure clauses are the same. Some are drafted to narrowly define an exclusive list of the events that constitute force majeure (e.g., natural disasters, strikes), while others broadly define a force majeure event as any unforeseen event that renders a party's performance impossible.

Precisely defining these parameters is perhaps less important if the parties have carefully and explicitly addressed all of the risks and issues listed above. That said, the parties should carefully consider whether regulatory or similar changes should be included as force majeure events, or whether they should be excluded in favor of more explicit risk allocation language. Ultimately, it is best practice to explicitly address the allocation of as many foreseeable risks as possible (e.g., regulatory changes, use case changes, warranted operating parameters, clear performance standards) instead of relying on a broad force majeure clause.

Insurance Coverage for Energy Storage Performance

As the energy storage industry matures, secondary products and services continue to develop to support the storage sector. The insurance market is one of these secondary products, including insurance products that cover battery storage performance.

Insurance products can play an important role in managing risks for energy storage manufacturers, developers, and customers. Appropriate insurance products can help manufacturers spread out the risks of the system warranties that they offer. System performance warranties or guarantees can be a considerable expense, especially in the case of long-term warranties or guarantees that manufacturers make to developers or operators of energy storage systems. Carrying the risks of servicing extended warranties on a balance sheet could inhibit a manufacturer's ability to secure financing for other activities or otherwise act as a drag on other business operations.

Likewise, insurance allows an energy storage system customer to mitigate the risk associated with relying on a manufacturer's battery performance warranty. Behind-the-meter energy storage customers usually use storage systems to reduce the volatility of energy costs or improve power reliability over a significant period of time. These customers rely on the manufacturer's warranty for storage performance to make sure that those savings and efficiencies are realized (i.e., the storage system provides adequate service during the term of the storage service contract, or the manufacturer makes up the difference if not).

By purchasing a storage solution from a manufacturer with a battery performance insurance policy, a customer can have more confidence that the manufacturer or its insurer will cover any performance deficit during the term of the insurance policy, particularly in an emerging technologies industry like energy storage. Where the parties extend the insurance contract to cover a specific storage system installation, the insurance company will pay for any performance deficiencies during the warranty period, even if the manufacturer is not able to honor the warranty due to insolvency or bankruptcy.

In March 2019, Munich Re announced that it has created the "world's first long-term insurance for battery performance" to cover battery manufacturers' battery performance warranties. Munich Re stated that ESS Inc. (ESS), a manufacturer of a flow battery energy storage system, is the company's first customer for a 10-year battery performance insurance product and that Munich Re hopes to expand its coverage to performance of mobile battery systems in electric vehicles. In this scenario, ESS already offers a lifetime guarantee for its flow batteries' performance—but the Munich Re insurance policy would provide customers additional assurance that ESS or Munich Re will honor the terms of the performance warranty during the coverage period.

Munich Re and other insurers will likely continue to develop additional insurance products to help manage the risks associated with the growing storage sector generally and battery storage solutions specifically. Parties are negotiating these insurance contracts in an evolving and highly regulated environment with limited legal precedent and industry experience, indicating that battery performance insurance contracts may be bespoke agreements for some time. Issues like the scope of coverage, who controls battery dispatch, and the transferability of the insurance contract will need to be reviewed closely. Parties will be well served to consider these contracts carefully, and the risk allocations they have reduced to writing, so that neither the insured nor the insurer will be surprised about who bears the cost in case of a loss event.

Interconnection

Energy storage projects generally undergo the same interconnection processes as same-sized renewable and traditional generation resources, despite the fact that most battery storage systems cannot operate at full capacity 24 hours a day and have many other significant technical and operational differences (such as the ability to act as both generation and load). For instance, while certain behind-the-meter projects may be non-exporting or inject energy onto the grid during limited and predictable times, many state interconnection procedures subject these resources to the same level of scrutiny as traditional generators. Some states, like California, have fast-track procedures that recognize a storage resource's unique load and dispatch profile.

For utility-scale storage projects, interconnection is regulated by FERC (although Qualifycing Facilities may seek to interconnect using state procedures). The owner must typically apply for interconnection to the transmission or distribution system owner or operator and then undergo a comprehensive independent or queue cluster study process, pay for any system upgrades

Interconnection issues and confusion can delay energy storage projects, impact financing, and lead to higher energy costs for customers.

necessary to ensure deliverability of energy, and negotiate an interconnection agreement. This process rarely takes fewer than 12 months and can sometimes take 30 months or longer. It is often assumed that the storage resource will inject its maximum capacity at any particular time, which overlooks some of storage's key advantages.

Interconnection issues and confusion can delay energy storage projects, impact financing, and lead to higher energy costs for customers. For behind-the-meter storage resources, or for storage resources that will not sell into FERC-jurisdictional wholesale markets, some state jurisdictional tariffs allow developers to fast-track or otherwise undergo a shorter interconnection procedure. Some states, like California, have begun proactively addressing these challenges in state public utility commission rulemaking proceedings, including establishing faster dispute resolution producers for interconnecting storage resources.

Interconnection issues may also arise when energy storage is either being added to or will replace all or a portion of an existing generating unit. Generally speaking, adding storage resources that will exceed the total MW of energy allowable under the existing interconnection agreement will require a developer to undergo a study process similar to that required for a brand new interconnection. However, replacing, or "swapping out," all or part of an existing generator with some portion of energy storage may not necessarily require the time and expense of the full study process, assuming that the site's total MW capacity and electrical characteristics will not substantially change. Some generators may propose "limiting schemes" when incorporating energy storage into new or existing generation projects. For instance, an interconnection customer contemplating a combined generation and storage resource (e.g., storage paired with solar) may, with the transmission provider's agreement, propose to limit the maximum injection capacity to a lesser specified amount in its interconnection request. In that case, a combined resource may propose a control system, power relays, or both to limit the maximum amount of power that can be injected on to the grid at one time. Then, the transmission provider may measure the capacity of the energy storage device based on the capacity specified in the interconnection request, which may be less than the device's maximum capacity. However, experience with the implementation of FERC Order No. 845 should bring interconnection procedures more in-line with how ESRs are actually used and dispatched.

Requesting Tariff Waivers from FERC for Missed Interconnection Deadlines

During the interconnection process, a project is required to meet a number of specific milestone dates, including payment and data submission requirements associated with the interconnection study process. Recently, RTOs/ISOs have cracked down on missed milestones and late information submissions, removing projects from assigned queue positions even in circumstances where the interconnection customer missed a deadline by a few hours. RTOs/ISOs have also taken the position that, absent a waiver from FERC allowing the RTO/ISO to waive the applicable tariff requirement, removal from the interconnection queue is final and non-appealable.

Obtaining a FERC waiver for a missed milestone is a fact-specific process that requires the interconnection customer to demonstrate that (1) an error was made in good faith; (2) the scope of the waiver requested is limited; (3) a concrete harm will be remedied by the waiver; and (4) granting the waiver will not cause undesirable consequences, such as harm to third parties. Whether FERC grants a request is often dependent on the fourth factor and, accordingly, it is in the interconnection customer's best interest to seek a waiver from FERC on a prospective basis and as soon as possible. It is also best practice to communicate with the RTO/ISO and the transmission owner prior to filing a request for a waiver, as waiver requests are more likely to be granted if the RTO/ISO is aware of and does not oppose the request.

Permitting and Filing Issues

State and Local Permits

Several states require special storage-specific permits or applications for nonutility-owned storage projects. Before constructing an energy storage system, developers will typically have to apply for a local conditional use, building, and/or grading permit, as well as comply with any generally applicable state and local zoning, building code, or environmental review laws (like the California Environmental Quality Act). Some jurisdictions have streamlined permitting processes by co-locating battery energy storage systems with solar or wind generating facilities. Other jurisdictions (most notably New York City) have raised concerns about the perceived fire hazards associated with the storage of large banks of lithium-ion batteries.

Storage projects proposed on federal land will fall under the jurisdiction of the associated federal agency and its permitting regime (e.g., property managed by the Bureau of Land Management must adhere to the Federal Land Policy and the Management Act's Right of Way process). In addition, projects on federal land would have to meet federal environment review compliance and undergo National Environmental Policy Act review which may potentially involve the amendment of federal land use plans. Utility-owned storage projects will typically be approved using the standard state public utility commission methods, similar to the processes used for transmission lines, substations, and rate changes. For residential projects, California has required local jurisdictions to make available and accept online all applications for behind-the-meter advanced energy storage systems.

FERC Filings

Market-Based Rate Authority

Unless an exemption applies, entities that make wholesale sales of electric energy, capacity, or ancillary services, including ESRs, must obtain prior authorization from FERC. FERC allows sales of energy, capacity, and ancillary services at market-based rates if the seller and its affiliates lack, or have adequately mitigated, horizontal and vertical market power. For ESRs that are not affiliated with entities that own significant amounts of generation capacity or transmission facilities in the same market as the storage resource, the market power considerations are typically straightforward. Market-based rate authority is also required before sales of test power. Accordingly, timing of the application to obtain market-based rate authority is an important consideration when developing ESRs. FERC regulations require that market-based rate applications be filed at least 60 days before the date on which the entity intends to begin selling at market-based rates. While it is possible to seek a waiver of this 60-day requirement, such waivers are discretionary and FERC will not make such authorization effective any earlier than the day after filing. Thus, it is critical that market-based applications be filed before making *any* sales from an ESR.

Once a seller has market-based rate authority, it must notify FERC of any changes that alter the characteristics that FERC relied upon in reviewing the seller's market-based rate application. For example, a status change filing may be required if the seller or its affiliates acquire or develop 100 MW or more of cumulative generation capacity, or if they acquire or develop certain transmission facilities, or inputs to electric power production not previously disclosed to FERC. Effective 1 October 2020, such status change filings, which used to be made within 30 days of the change, now will be reported on a quarterly basis. Further, a seller with market-based rate authority will be required to report and maintain information regarding its affiliates, generation assets, long-term power purchase agreements, and inputs to electric power production in a "relational database." Energy storage companies with market-based rate authority must therefore continually evaluate the need to report changes with each new business change or new affiliation.

Certain entities are exempt from the requirement to obtain market-based rate authority. For example, qualifying small power production facilities that are 20 MW or smaller are exempt from the filing requirement and approval process.

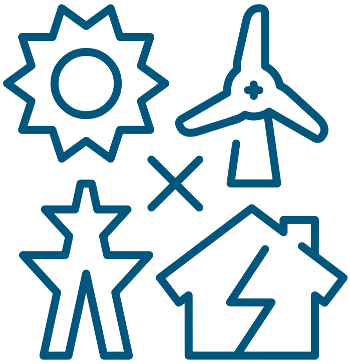
Public Utility Holding Company Act of 2005 (PUHCA)

A public utility holding company is a company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities of a public utility company or a holding company of any public utility company. A public utility company includes companies that own or operate facilities used for the generation, transmission, or distribution of electric energy for sale.

Unless otherwise exempted, public utility holding companies must maintain and make available to FERC such books and other records as FERC determines are relevant to the costs incurred by an associate public utility or natural gas company and necessary or appropriate for the protection of customers with respect to jurisdictional rates. One possible exemption from FERC's books and records requirements for public utility holding companies is if the holding company owns only one or more of the following types of facilities: (1) QFs; (2) exempt wholesale generators (EWGs); and (3) foreign utility companies. The criteria for EWGs and QFs can be applied to energy storage companies to qualify for the books and records exemption.

Exempt Wholesale Generator

An EWG is any person engaged in the business of owning or operating one or more eligible generating facilities and selling electric energy at wholesale. Although the EWG definition requires that the entity be exclusively in the business



of selling electric energy at wholesale, FERC has recognized certain incidental activities, such as selling ancillary services, as permissible activities to retain EWG status.

An entity obtains EWG status by either filing a notice of self-certification with FERC demonstrating it satisfies the definition of an EWG or submitting a filing to request a FERC determination that it satisfies the definition. A self-certification notice will be deemed temporarily granted upon filing until further action is taken by FERC. If FERC takes no action within 60 days of filing, the self-certification status is final. An entity must notify FERC within 30 days if there is any material change in facts that may affect its EWG status. All self-certification notices filed with FERC also need to be served on the state regulatory authority of the state in which the facility is located.

While FERC has acknowledged that electric storage devices do not readily fit into the traditional asset functions of generation, transmission, or distribution, it has accepted notices of EWG self-certification from ESRs that demonstrate that they will operate in such a manner that their facilities will be engaged directly and exclusively in selling electric energy at wholesale. Accordingly, to determine whether a particular energy storage facility will qualify as an EWG, the particular operational characteristics of the facility will need to be examined.

Qualifying Facilities

PURPA established a new class of generating facilities known as QFs that receive special rates and regulatory treatment. QFs fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities. Small power production QFs are 80 MW or less and have a primary energy source that is either renewable (hydro, wind, or solar), biomass, waste, or geothermal. Cogeneration QFs must meet certain operational and efficiency requirements and produce both electricity and another form of useful thermal energy (heat or steam) in a way that is more efficient than producing them separately.

In addition to being relevant to the PUHCA books and records exemption discussed above, QFs also benefit under federal law and FERC regulation by having, in certain circumstances, the option to require the electric utility with which they are directly interconnected to purchase their power. QFs may also qualify for additional relief from certain other regulatory burdens.

An owner or operator of a generating facility with a maximum net power production capacity of more than 1 MW may obtain QF status by either submitting a self-certification (FERC Order No. 556) or by applying for FERC certification. Self-certification notices must be served on the interconnecting utility and the state regulatory authority of the state in which the facility is located. A QF needs to recertify its status (submitting an updated Form No. 556) when the facts and representations in the self-certification on file with FERC can no longer be relied upon. Eligible facilities that are 1 MW or less are exempt from filing requirements and can therefore obtain QF status without any filing. In determining whether an energy storage facility can be a QF, the primary energy source behind the battery must be considered. If the primary energy source is one of those contemplated by the statue for conventional small power production, then the storage system may qualify as a QF. For example, a battery storage facility could claim QF status by asserting that its battery system will take its input from 100 percent renewable energy resources.

FERC considers the components of a generating facility when reviewing the QF status of a facility. If a component, such as the solar arrays, exceed the 80 MW statutory limit for a small power-producing QF, then the facility's QF status may be denied. Instances where a component of a facility is purposefully designed to output in excess of 80 MW does not support the argument that the facility may occasionally cross the 80 MW threshold for certain components.

Order No. 872, issued in July 2020, updated FERC's regulations implementing key parts of PURPA. Notable changes to the PURPA regulations include: (1) providing additional flexibility to set "avoided cost" rates for QF sales; (2) modifying the "one-mile rule" to allow for consideration that affiliated QFs more than one mile but less than ten miles apart may be at the same site; (3) revising procedures to challenge initial QF certification and recertification; (4) revising the threshold from 20 MW to 5 MW at which a utility may petition to terminate its obligation to purchase from QFs in certain conditions; and (5) requiring states to develop criteria that must be met for a QF to be entitled to a contract or legally enforceable obligation (also referred to as a LEO).

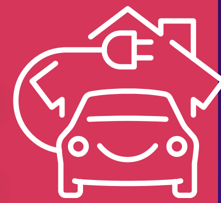
Transactions Involving Energy Storage Facilities

FERC has statutory authority to review and approve transactions involving public utilities, which may include transactions involving energy storage facilities. For transactions requiring FERC approval, FERC authorization must be obtained before completing the transaction. FERC must act on applications for transaction approval within 180 days, but can toll the time for an additional 180 days for good cause. Applicants can request expedited treatment, however, and in practice most applications are approved in fewer than 180 days. Nonetheless, energy storage companies engaged in transactions subject to FERC approval should factor in time for the approval process, particularly for transactions involving novel applications of energy storage technologies.

LOOKING AHEAD

Multiuse Applications

When evaluating energy storage options at the wholesale, distribution, or behind-the-meter levels, sophisticated industry participants consider the multiple applications that energy storage systems can provide across the full electricity value chain. These multiple uses can include:



ISO/RTO LEVEL	UTILITY LEVEL	CUSTOMER SIDE (BEHIND THE METER)
Energy Arbitrage	Resource Adequacy/Flexible Resource Adequacy	Time-Of-Use Bill Management
Frequency Regulation	Distribution Deferral	Increased PV Self-Consumption
Spinning/Non-Spinning Reserves	Transmission Congestion Relief	Demand Charge Reduction
Voltage Support	Transmission Deferral	Backup Power
Black Start	Peaker Deferral	

Depending on the goal for the particular storage system, energy storage system operators can combine more than one of these energy storage applications to increase the system's value proposition and more quickly recoup investment costs, optimizing the system for multiuse applications that "stack" energy storage's contributions to the energy market. Operators are finding more and more ways to create value from energy storage, including payments for ancillary services and replacing natural gas-dependent infrastructure. Energy storage management software is improving as well, allowing storage operators to deploy their storage assets as efficiently and economically advantageously as possible.

One issue, however, is how market participants should separately value each use of an ESR. For instance, while there is pricing for resource adequacy and spinning reserves services in most wholesale electricity markets, it's more difficult to value avoided transmission and distribution upgrades.

Moreover, due to structural or regulatory hurdles and barriers to entry, not all of these applications can be combined readily with each other. For instance, utility-level applications like transmission deferral cannot be combined easily with behind-the-meter applications like time-of-use bill management. Some state-level storage incentives are unavailable to storage resources that already participate in net-metering programs.

Most observers agree that regulatory changes are needed to unlock the full value of ESRs. Utilities and grid operators are considering different scenarios where storage systems can provide services along multiple parts of the electricity value chain. One example is in California, where utilities have considered the possibility of a retail energy storage system(s) providing wholesale demand response or permanent load reduction (which CAISO could treat as a supply resource under its tariff).

From a regulatory perspective, California is the first state to establish rules on how ESRs can participate in several market segments at once. In January 2018, the CPUC adopted 12 rules to evaluate multiuse storage applications and directed the state's utilities to comply with these rules.

CPUC RULES FOR EVALUATING MULTISTORAGE APPLICATIONS

1 Resources interconnected in the customer domain may provide services in any domain.

2 Resources interconnected in the distribution domain may provide services in all domains except the customer domain, with the possible exception of community storage resources.

3 Resources interconnected in the transmission domain may provide services in all domains except the customer or distribution domains.

4 Resources interconnected in any grid domain may provide resource adequacy, transmission, and wholesale market services.

5 If one of the services provided by a storage resource is a reliability service, then that service must have priority.

6 A single storage resource may not contract for two or more different reliability services from the same capacity in a single or multiple domains over the same time interval for which the resource is committed to perform. The storage provider must not enter into multiple reliability service obligations such that the performance of one obligation renders the resource from being unable to perform the other obligation (except as provided in Rule 7).

7 A single storage resource may contract for resource adequacy capacity and provide wholesale market reliability services using the same capacity and over the same time interval. For example, if a storage resource is providing local resource adequacy capacity, it may meet its resource adequacy must offer obligation by providing any service in the wholesale service domain using its resource adequacy capacity.

8 If using different portions of capacity to perform services, storage providers must clearly demonstrate, when contracting for services, the total capacity of the resource, with a guarantee that a certain, distinct capacity be dedicated and available to the capacity-differentiated reliability services.

9 For each service, the program rules, contract, or tariff relevant to the domain in which the service is provided must specify enforcement of these rules, including any penalties for non-performance.

10 In response to a utility request for offer, the storage provider is required to list any additional services it currently provides outside of the solicitation. In the event that a storage resource is enlisted to provide additional services at a later date, the storage provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this rule is to provide transparency in the energy storage market.

11 For all services, the storage resource must comply with availability and performance requirements specified in its contract with the relevant authority.

12 In paying for performance of services, compensation and credit may only be permitted for those services that are incremental or distinct. Services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

The CPUC is also soliciting feedback from a stakeholder working group on certain issues, such as metering of time-differentiated multiuse applications, enforcement of certain contract provisions, and whether any CPUC-jurisdictional rules or tariffs must be modified to accommodate multiuse applications. The working group filed its report on 9 August 2018, providing comprehensive feedback across a range of issues. Regulators and electricity system stakeholders in Hawaii, Massachusetts, Minnesota, New York, and Texas are all considering similar issues.

On the industry side of the value stacking question, utilities in Florida are considering methods to unlock additional value from energy storage facilities. Jacksonville Energy Authority (JEA), Jacksonville, Florida's municipal utility, is offering a rebate of up to US$4,000 for residential or business customers who install qualifying energy storage systems to complement the customer's approved renewable energy system. JEA has also adjusted its net metering incentives to encourage its customers to install energy storage with distributed renewable generation. Other utilities in the state, including Florida Power & Light and Lakeland Electric, are considering initiatives to unlock value associated with energy storage.

ENGIE Storage has announced plans to pay storage project developers for dispatch rights in order to use those storage resources to participate in wholesale electricity markets, alleviating merchant risk for the developer. Initially offering this product only in the ISO New England market, ENGIE announced that its first customer will be Syncarpha Capital with six community solar projects totaling 19 MW and 38 MWh.

Given the financial benefits presented by multiple use storage applications, one can expect additional development of the technical, financial, regulatory, and legal changes necessary to unlock the full value of a storage resource. These structures will include, for example, lenders and borrowers coalescing around financial modeling that incorporates stacking multiple uses for an energy storage system, grid regulators and operators addressing tariff barriers to multiple use applications for energy storage systems, and owners and operators of energy storage systems

developing contractual and compliance processes to operate these storage systems for multiple customers across different regulatory programs. All of these issues, and many more, provide the opportunity to shape the energy storage market going forward and promise a more reliable, resilient grid.

Renewables Plus Storage

Hybrid Projects: Integration of Energy Storage and Renewable Electricity Generation

The combination of renewables generation, cost-effective energy storage, and advanced power control technologies has been called a killer app for energy. Hybrid generation-storage solutions offer a wide range of benefits for both customers and grid operators. Applications for hybrid projects span the market, from microgrids and behind-the-meter hybrids for residential and commercial customers, to utility-scale projects serving as important additions to grid service offerings.

Costs for both energy storage and renewables generation have been steadily decreasing. With the improving economics, many use cases for solar-plus-storage and wind-plus-storage are coming into economic feasibility. Of the 13 different energy storage services identified in the recent Rocky Mountain Institute (RMI) report *The Economics of Battery Storage*, RMI states at least eight can now be achieved cost-effectively in renewable-storage combinations. These use cases include demand charge reduction and peak shaving to reduce costs resulting from time-of-use charges, frequency regulation, and grid services such as reactive power and voltage control. For commercial customers, distributed storage-generation hybrids can provide a reliable source of backup power, a need that is becoming more imperative as disruptive weather events become more common. A global consultancy, Lux Research, has estimated that the global market for distributed storage for solar systems will reach US$8 billion by 2026.

New integrated renewables generation and energy storage projects are coming online rapidly, some with pricing that would have seemed years away as recently as 2016. In June 2017, Tucson Electric Power (TEP) announced a PPA for a project combining 100 MW of solar and a 30 MW, 120 MWh energy storage facility with a PPA rate of 4.5 cents per kWh over its 20-year life. In January 2018, Xcel Energy released information from its August 2017 RFP for Colorado, showing median bids of US$36/MWh for solar-plus-storage and US$21/MWh for wind-plus-storage.

Other technologies may be poised to bring costs down even further. For example, ViZn Energy Systems (ViZn) offers a flow battery and solar hybrid that it asserts will be better suited to large-scale storage firmed renewable power plants such as the TEP project. ViZn analyzed its flow battery solution

Lux Research, has estimated that the global market for distributed storage for solar systems will reach US$8 billion by 2026.

using the metrics of the TEP project and concluded that it could compete at the price of 4.0 cents per kWh, based on substantially lower battery replenishment costs over time.

The combination of solar and storage may eventually emerge as an economically superior alternative to natural gas peaking plants. When costs for integrated storage drop below a certain level, whether it is one half or even more of today's prices, a tipping point is likely to occur that could see this solution displace gas peakers on a widespread, even global basis. In anticipation, a number of U.S. utilities have already launched programs to procure or otherwise support hybrid storage projects. Moreover, generators are beginning to recognize the benefits of transforming existing wind or solar facilities into a hybrid system.

Integrated Solar-Plus-Storage Power Purchase Agreement (Solar-plus-Storage PPA)

Solar-plus-storage PPAs are already common in places like Hawaii, where the cost of electricity supports the economics of combining renewable energy with storage technology. The solar-plus-storage PPA used in such behind-the-meter applications will be similar to the third-party PPA structure commonly used for the on-site solar projects.

Solar-plus-storage PPAs have historically been used primarily for behind-the-meter projects in markets where the retail price of electricity is high and net metering may no longer be a viable option. Utility-scale integrated solar and storage systems, however, are now making their presence felt. In 2015, Kauai Island Utility Cooperative (KIUC) signed a 20-year PPA for such a project that would store solar energy from 17 MW of solar PV during the daytime and make 52 MWh of storage (i.e., 13 MW of storage available for four hours) to help meet the cooperative's evening peak. In 2017, KIUC entered into a PPA with AES Distributed Energy, which is expected to combine 28 MW of solar PV with 20 MW of batteries capable of five hours of discharge. The price tag for the output of the AES project is reported to be 11 cents per kWh, a decline from the 13.9 cents per kWh reported for the previous project. In 2019, the HPUC approved six grid-scale solar-plus-battery storage projects in Hawaii, adding a total 247 MW with almost 1 GWh of storage in the state. The estimated costs will range from eight to ten cents per kWh, already a slight improvement from the preceding AES project and a marked decrease from the 15 cents per kWh needed for fossil fuel generation on the island.

Hawaii has been a logical proving ground for hybrid solar-plus-storage projects because the market price for electricity is set by imported fossil fuels, which results in the highest retail electricity prices in the United States. Nevertheless, integrated energy storage and renewable energy projects are proving to be viable projects on the mainland, at least where there is a strong solar resource. For example, TEP announced in 2017 that it had entered into a PPA with NextEra Energy for the output of a 100 MW solar PV project and a 30 MW, four-hour energy storage system (120 MWh), at a reported all-in price of 4.5 cents per kWh. The project is expected to be in service by the end of 2020. More recently, in February 2019, Portland General Electric announced that it had entered into a transaction with NextEra Energy to integrate 300 MW of wind generation, 50 MW of solar generation and 30 MW of battery storage at the Wheatridge Renewable Energy Facility in Morrow County, Oregon. PGE described the project as "the first of this scale in North America to co-locate and integrate these three technologies."

Business Model and Regulatory Issues

While the benefits are clear, integrated renewable plus storage projects pose regulatory and financing challenges. The theoretical returns available through the prospect of stacking multiple value streams can be difficult or impossible to attain in practice given regulatory and utility constraints. They also present modeling challenges in assessing net present value of and projecting future cash flows.

Some of the key issues for project finance for renewables-storage hybrids include:

Tax Credit Uncertainties

The IRS has provided guidance regarding eligibility of storage to be considered part of a solar project to receive the federal ITC, stating that if the storage equipment is part of a single project with solar equipment, the storage investment will be eligible for the ITC provided at least 75 percent of the charging of the storage unit is through the solar generation. However, the IRS indicated that the amount of the credits would be calculated over time, based on the percentage of charging from solar versus charging from the grid. This approach is inconsistent with standard structures for tax equity financing, where the amount of the tax credits is locked in at the outset and certainty is required to assess the rate of return. The need to maintain eligibility for the ITC could also result in sacrificing potential economic gains that could be realized by charging from the grid through forms of energy arbitrage. On the other hand, the flexibility of storage systems to provide different grid services and economic use cases over time may serve to mitigate these concerns. Once the available tax credits are obtained, the project may then be reconfigured to provide other benefits.

Regulatory Compliance and State Public Utility Commission Requirements

Solar-plus-renewables projects can raise tricky issues for compliance with federal and state regulatory requirements. At the federal level, adding storage that may be charged from the grid can call into question a renewable generator's ability to meet QF status for exemption from utility requirements. Owners must also evaluate whether storage facilities may subject them and any affiliates and investors to potential requirements under the Public Utilities Holding Company Act. At the state level, varying approaches to the regulation of "generation" facilities and "public utilities" can further contribute to the regulatory uncertainties. Finally, determining and meeting PUC interconnection requirements can become more challenging for hybrid storage projects and can result in increased interconnection fees and delays in the study process.

Role of Storage in Corporate PPAs

Large corporate power purchasers have been a major driver of renewables project development over the past three years. Several large corporates are showing active interest in hybrid projects that include storage, both on-site and in connection with virtual power purchase agreements.

For corporate buyers, the ability to support sustainability claims is a key ingredient. Storage will typically be charged exclusively with solar energy until the ITC recapture period expires, after which it may charge either from solar or the grid. Where a project includes storage that may at some point charge from the grid, offtakers should consider the effect that the charging arrangement will have on the renewable energy credits that the project is expected to produce.

Expanding the Types of Hybrid Combinations

While much of the focus has been on solar-plus-storage, combining storage with wind power or other generation such as natural gas or biomass is gaining traction. Danish energy giant Ørsted has completed a project to add a 2 MW battery storage system to a 90 MW wind farm in the United Kingdom. In November 2018, BP installed a 212 kW battery storage system for the first time at one of the company's wind farms. The company intends to implement similar storage technology at its 12 other wind energy sites in the United States. AES recently announced a US$2 billion project to combine 100 MW of four-hour duration storage with a repowered 1.3 GW combined cycle gas plant, under a 20-year PPA with SCE. In fact, SCE has already installed a pair of 11 MW, 4.3 MWh battery storage systems at two existing 50 MW gas peaker plants in the Los Angeles basin. The batteries allow SCE's gas peakers to respond more quickly to frequency regulation signals and are expected to allow the peakers to avoid operating costs, reduce emissions, and cut water use.

AES also has combined storage with wind in prior projects, notably the 98 MW Laurel Mountain Wind Farm in West Virginia, which includes a 32 MW battery storage project. These are just some early examples as the potential combinations are expanding rapidly with the improving technology and economics.

For a given project, the decision whether to combine storage and generation may turn on assessment of regulatory and financing issues. The potential benefits may be large, but the path to achieving them must be clear and viable. The industry has much work ahead in supporting market reforms and achieving financing models that will support widespread deployment of storage and renewables hybrids. With improving economics and more advanced technologies, however, the incentives to tackle and solve these problems are stronger than ever.

Vehicle to Grid

Vehicle-to-grid (V2G) technology is being studied as a means of addressing many of the inefficiencies of intermittency posed by renewable resources. V2G is characterized by the reciprocal flows of power between the grid and electric or plug-in hybrid vehicles (collectively, EVs). The goal of V2G technology is to transform EVs into mobile energy storage systems that can act as virtual distributed generators—storing excess wind and solar generation during off-peak periods, and then offering that power back to the grid during periods of peak demand.

Because most vehicles remain parked for an average of 23 hours each day, EV batteries can serve as temporary storage to soak up excess energy generated from renewable sources. By releasing energy during peak demand, a decentralized network of EV batteries can also alleviate transmission congestion and defer capital investment in distribution, transmission, and peaking assets that might otherwise be needed. V2G's stabilizing effects could also contribute to solving the problem of the "duck curve," where periods of peak renewable generation and of weak demand coincide (and vice versa).

The EV market is expected to accelerate over the next decade, posing several opportunities for V2G technology. In August 2020, the cumulative plug-in vehicle sales in the United States has reached 1.6 million units, 1 million of which were EVs, spurred in part by federal and state incentives that recognize EVs lower carbon footprint. EVs are gaining an even larger market share in Europe and around the globe. China aims for EVs to comprise one-fifth of its annual car sales by 2025 and has considered a target of 50 percent in 2035. The UK government is targeting the achievement of 50 percent EV saturation by 2030 and "effectively zero emission" by 2040. In addition, Volkswagen is planning to build 28 million electric vehicles by 2028 by expanding manufacturing to the United States.

As the EV market continues to expand, major corporations and universities are responding to market signals and have begun racing toward the broad implementation of V2G technology in EVs. For example, PG&E and BMW demonstrated the potential of V2G technology through their joint i_ ChargeForward program in 2017. The program tested 100 EVs during 209 demand response events over an 18-month period, and found that

EVs utilizing the V2G system provided 19,500 kWh of response—roughly 20 percent of the total contribution—during those events. Audi and Nissan have both launched pilot projects that link EV charging stations, rooftop solar panels, and stationary energy storage to balance services to the grid. BMW, Mercedes Benz, Enel, Daimler AG, and others are also pursuing similar efforts and initiatives. The University of California, Los Angeles, is researching improvements to attain maximum V2G power generation from each EV, while also improving response time and power-sharing control. In September 2020, Fiat Chrysler launched the first phase of its V2G pilot project in Italy. The project will be the world's largest V2G installation when Fiat connects the full fleet of 700 EVs in late 2021.

In the United States, school districts have led the charge for V2G integration as large fleet vehicles with predictable routes are ideal V2G resources. EV school bus pilot programs have launched in California (through SDG&E), New York (through Consolidated Edison Co.), and Virginia (through Dominion Energy). Power producers in North Carolina and Florida are launching similar programs. Most recently, Nuvve Corporation and Blue Bird Corporation have partnered to equip and sell EV vehicles with V2G technology nationally.

As V2G technology continues to develop, there will likely be new and novel relationships among vehicle owners, EV charging station owners, and local utilities. A legal framework will need to be developed to govern both the purchase and sale of energy among these entities and for integrating EVs with utility distribution systems. There are also implications for regulators, with FERC, RTO/ISOs, and state utility commissions all having a role to play in ensuring effective integration of V2G technology.

Hydrogen Storage

Hydrogen now appears poised to play a significant role in the energy economy and has the potential to add a new twist to the energy storage conversation. While it can be produced from a number of resources, producing hydrogen from renewable resources, including wind, solar, and hydropower, has a number of advantages. These include the ability to claim the hydrogen as green (among the multiple hydrogen color options, each of which carries an indicator of the relative carbon footprint associated with production), as well as the ability to use hydrogen as a form of energy storage for the renewable resource.

Presently, the most commercially viable option for hydrogen production from renewable power sources is via electrolysis.[1] During electrolysis,

1 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019 ("[E]lectrolysers are already commercially available and entail the immediate potential of creating a buffer for the growing volume of intermittent wind and solar power."); *see also* Public Utility District No. 1 of Douglas County, Renewable Hydrogen, https://douglaspud.org/Pages/Renewable-Hydrogen.aspx#:~:text=Traditionally%20hydrogen%20is%20produced%20using,or%20consumption%20of%20the%20fuel (last visited Aug. 23, 2020) (discussing production of hydrogen from hydropower).

electricity splits water molecules into hydrogen and oxygen within a device called an electrolyzer.[2]

Once the hydrogen is produced, it can be stored for later use, either in its own right or to produce electricity. This ability to effectively store renewable power as hydrogen provides flexibility to smooth the differential between the relative intermittency of renewable electricity production and shifts in both daily and seasonal power demand. For example, an electrolysis unit could be co-located with a wind or solar generator where variable electricity is being curtailed. Instead of curtailing the surplus electricity, the generator could continue to produce electricity and sell it to a co-located electrolysis unit to produce hydrogen. The hydrogen could then be delivered directly to a natural gas pipeline (subject to limits required to address safety, leakage, or gas quality concerns), or it could be used as a feedstock for a methanization process that produces methane suitable for injection to the pipeline.[3] If the local geology is favorable, the hydrogen could also be stored in depleted hydrocarbon reservoirs or salt caverns for later use. The stored hydrogen could later be used in fuel cells to generate electricity directly or as fuel for hydrogen cars, or it could be used to produce an intermediate product in order to overcome hydrogen storage and transportation challenges.[4]

The economic case for seasonal storage in a given region depends on a number of variables, including renewable energy penetration, resource adequacy needs, the growth of carbon taxes or other carbon regulation, the price of natural gas, and seasonal or annual variation in generation or in loads.[5] The prospects are daunting at this point, and very long-duration hydrogen storage may not be economically viable in the United States for some time, although several European projects are underway.[6] That said, those who have followed the development of the wind, solar, hydropower, natural gas, and energy storage industries in the United States know that cost barriers can tumble quickly and unexpectedly. At least one consortium of developers is pursuing a large-scale storage project in Utah: the Advanced Clean Energy Storage project is intended to provide storage services for 1,000 MW of wind in the form of compressed air or hydrogen stored in a salt cavern.[7]

2 DEP'T OF ENERGY, HYDROGEN PRODUCTION: ELECTROLYSIS, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

3 KEN DRAGOON, POWER TO GAS: OPPORTUNITIES FOR GREENING THE NATURAL GAS SYSTEM 19-21 (2018).

4 ROB VAN GERWEN, MARCEL EIJGELAAR & THEO BOSMA, THE PROMISE OF SEASONAL STORAGE 27 (2020).

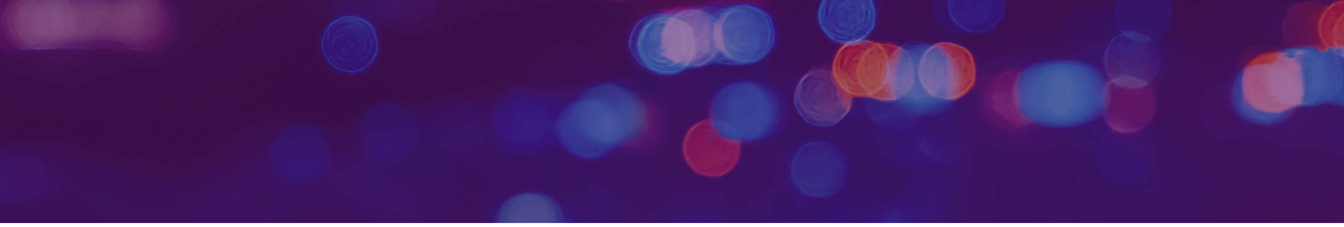
5 *Id.*

6 DRAGOON, *supra* note 3, at 27–28.

7 Umar Ali, *How salt caverns could transform renewable energy storage for the US*, POWER TECH. (Aug. 29, 2019), https://www.power-technology.com/features/how-salt-caverns-could-transform-renewable-energy-storage-for-the-us/#:~:text=A%20new%20project%20called%20Advanced,or%20compressed%20air%20by%202025. (last visited August 13, 2020).

GLOSSARY

ACC	Arizona Corporation Commission
ACES	Advancing Commonwealth Energy Storage
AEP	American Electric Power
AGC	automated generation control
APS	Arizona Public Service
BESS	battery energy storage system
BPU	New Jersey Board of Public Utilities
BTA	Build Transfer Agreement
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CEC	California Energy Commission
ConEd	Con Edison, Inc.
CPUC	California Public Utilities Commission
CSA	Capacity Services Agreement
CSRs	co-located storage resources
DCSSA	Demand Charge Shared Savings Agreement
DER	distributed energy resource
DLM	dynamic load management
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DPU	Department of Public Utilities
DRESA	Demand Response Energy Storage Agreement
EFA	Energy Freedom Act
EPC	engineering, procurement, and construction
ERCOT	Electric Reliability Council of Texas
ESDER	energy storage and distributed energy resources
ESI	Energy Storage Initiative
ESRs	energy storage resources
EWG	exempt wholesale generator
FCM	Forward Capacity Market
FDNY	Fire Department of the City of New York
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GW	gigawatt
GWh	gigawatt hour
HCEI	Hawaii Clean Energy Initiative



HECO	Hawaiian Electric
HNEI	Hawaii Natural Energy Institute
HPUC	Hawaii Public Utilities Commission
IOU	investor-owned utility
IRS	Internal Revenue Service
ISO-NE	ISO New England Inc.
ISO	independent system operator
ITC	investment tax credit
JEA	Jacksonville Energy Authority
KIUC	Kauai Island Utility Cooperative
kW	kilowatt
kWh	kilowatt hour
LADWP	Los Angeles Department of Water and Power
LAES	Liquid Air Energy Storage
LDs	liquidated damages
LEO	legally enforceable obligation
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
MACRS	modified accelerated cost recovery system
MassCEC	Massachusetts Clean Energy Center
MESA	Modular Energy Storage Architecture
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt hour
NERA	New England Ratepayer Association
NFPA	National Fire Protection Association
NGR	non-generator resource
NTIG	New Technology Implementation Grant
NYISO	New York Independent System Operator
NYPSC	New York State Department of Public Service
NYSERDA	New York State Energy Research and Development Authority
NYSPSC	New York State Public Service Commission
OPUC	Public Utility Commission of Oregon
OZ	Opportunity Zone
PDR	proxy demand response
PGE	Portland General Electric
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, L.L.C.

GLOSSARY

PPA	power purchase agreement
PSE	Puget Sound Energy
PTC	production tax credit
PUC	Public Utility Commission
PUCN	Public Utilities Commission of Nevada
PUCT	Public Utility Commission of Texas
PUHCA	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
QOF	qualified opportunity fund
QOZB	qualified opportunity zone business
QOZBP	qualified opportunity zone business property
RA	resource adequacy
RegD	Regulation D
REST	Renewable Energy Standard and Tariff
RFO	Request for Offer
RFP	Request for Proposal
RMI	Rocky Mountain Institute
Roadmap	New York State Energy Storage Roadmap
RPS	Renewable Portfolio Standard
RTO	regional transmission organization
SATOA	storage facility as a transmission-only asset
SCC	Virginia State Corporation Commission
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures
SGIP	Self-Generation Incentive Program
SMART	Solar Massachusetts Renewable Target
SnoPUD	Snohomish County Public Utility District
SPP	Southwest Power Pool Inc.
TEPCO	Tucson Electric Power Company
UTC	Washington Utilities and Transportation Commission
V2G	vehicle-to-grid
VCEA	Virginia Clean Energy Act
VPPA	virtual power purchase agreement
WADOC	Washington State Department of Commerce

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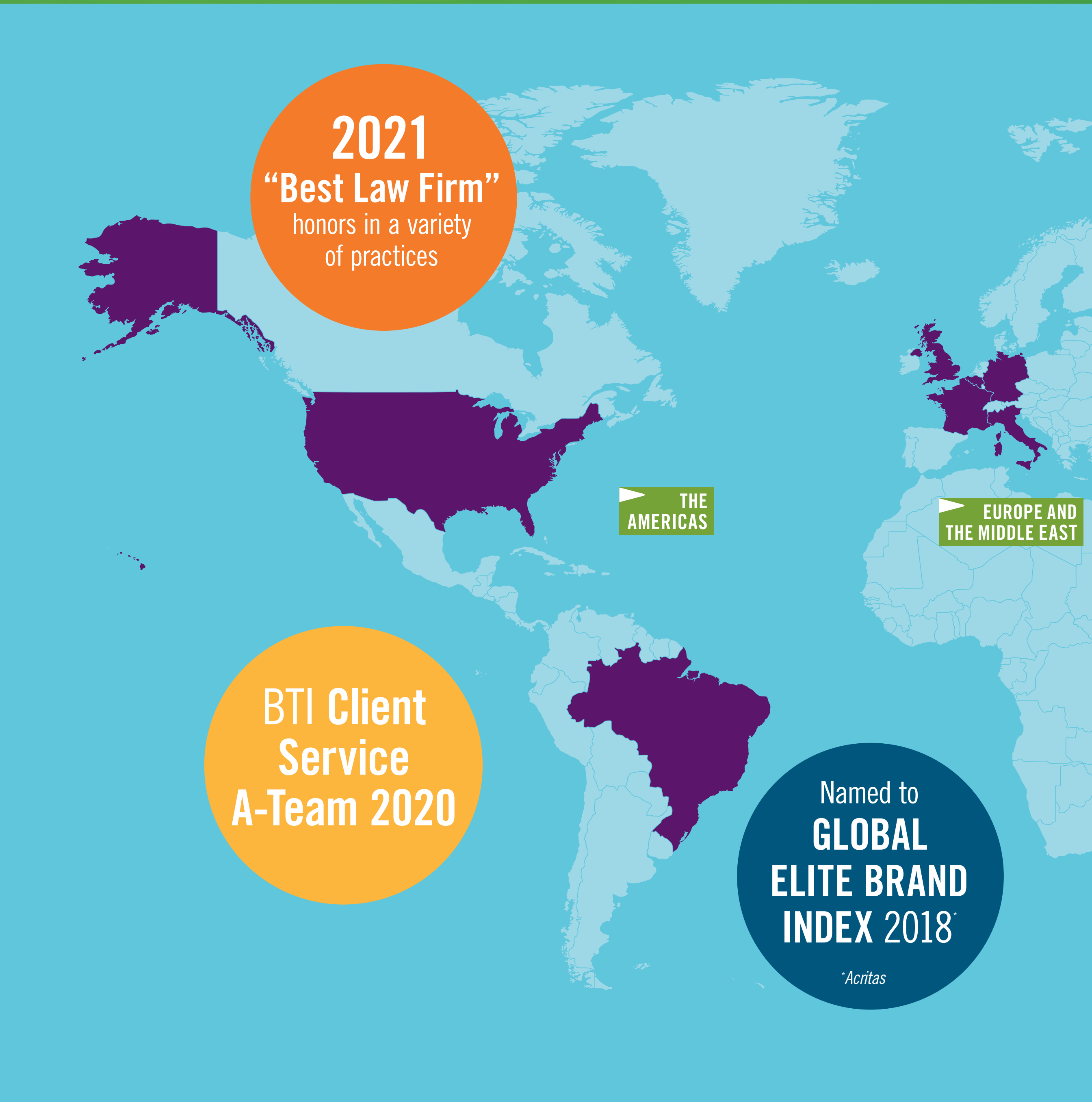

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