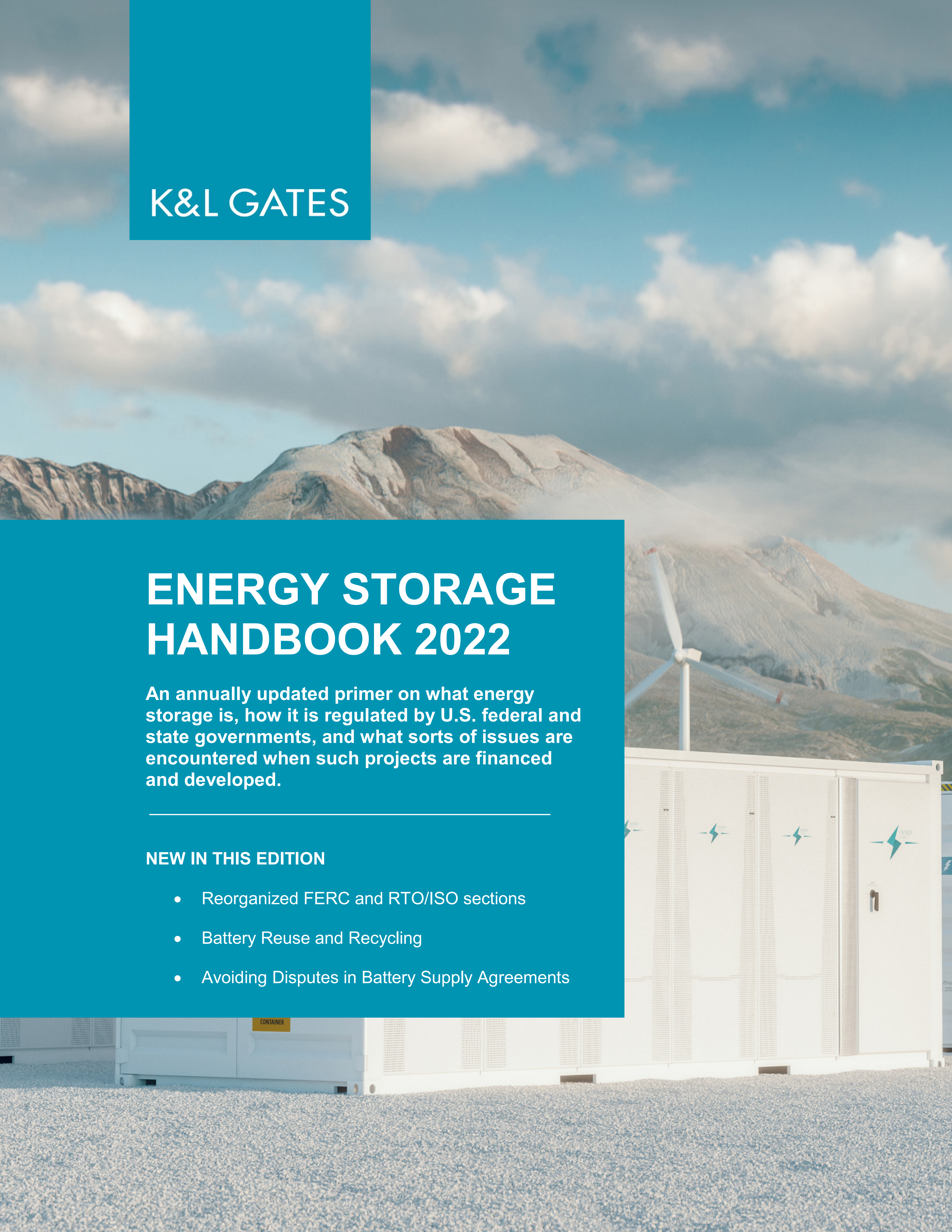

K&L GATES

ENERGY STORAGE HANDBOOK 2022

An annually updated primer on what energy storage is, how it is regulated by U.S. federal and state governments, and what sorts of issues are encountered when such projects are financed and developed.

NEW IN THIS EDITION

- Reorganized FERC and RTO/ISO sections
- Battery Reuse and Recycling
- Avoiding Disputes in Battery Supply Agreements

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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 state renewable portfolio standards and tax credits, mandates, grants, and other incentives (led mostly by state governments) has spurred the rapid development of carbon-free and renewable power generation assets, including wind and solar facilities. Technological advancements and declining costs 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 fossil fuel-dependent, controllable (dispatchable) resources to renewable, intermittent resources and provide many other supplementary benefits to the grid, such as ancillary services that maintain the real-time security of the interstate transmission system. By capturing energy at the time it is generated and using it to serve load 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% 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

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 decade will constitute an extremely innovative period for energy storage with the lithium-ion battery at the forefront. Such dramatic innovation will be needed 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 higher 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 largescale 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 hydrogen 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 during peak demand 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 water can be heated to 85° C during summer months when solar energy resources are plentiful and cooled 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

Compressed air energy storage (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.

FEDERAL LAWS AND REGULATIONS SHAPING ENERGY STORAGE DEVELOPMENT

Department of Energy Initiatives and Loan Guarantees

The U.S. Department of Energy (DOE) has also been actively fostering growth in ESR deployments. In January 2020, the DOE launched its "Energy Storage Grand Challenge" (ESGC). The ESGC is a comprehensive program designed to accelerate development, commercialization, and utilization of ESRs, and to catalyze domestic manufacturing capabilities. Throughout 2020 and 2021, the DOE has hosted a series of workshops that focus on ESR manufacturing, markets, and regions and through various working groups, DOE has published numerous reports analyzing the current and future ESR markets and opportunities.

In March 2021, the DOE began design and construction of a US$75 million "Grid Storage Launchpad" (GSL), a research and development facility located at Pacific Northwest National Laboratory (PNNL) in Richland, Washington. The GSL leverages investments by Washington state, Battelle, and PNNL and will be completed in 2025. Once completed, the GSL is designed to spur collaboration by multi-disciplinary researchers, industries, and universities in order to lower barriers to new technologies and innovation. The facility will also offer testing and validation services to next generation ESRs under the rigors of grid operating conditions, study the abilities and applications of next generation ESRs, as well as develop strict performance requirements.

As another example of the DOE's efforts to advance domestic manufacturing capability, the Federal Consortium for Advanced Batteries, led by the DOE, recently released a National Blueprint for Lithium Batteries 2021-2030, which identifies short- and long-term objectives, and seeks to guide investments in a domestic lithium-battery value chain that spans the lifecycle of battery materials from raw material production to end-of-life recycling and reuse.

The DOE also plays a prominent role in offering government-sponsored financing to next generation storage technologies through its Loan Programs Office (LPO), which has authority to issue US$4.5 billion in loans for innovative Renewable Energy and Efficient Energy Products located within the United States. The LPO issues loan guarantees to projects in the interest of leveraging private investments and to cover the gap in funding to develop and advance these technologies or provide financing to technologies that are first-of-its-kind or not yet well understood by the private sector. The LPO is able to offer flexible and custom financing options to meet the specific needs of a project that meets all requisite criteria, with interest rates equal to the U.S. treasury rate. Throughout the life of the loan guarantee, the LPO provides support by in-house financial, technical, legal, risk mitigation, portfolio management, and environmental professionals. The DOE has indicated a keen interest in accelerating the development of long-duration storage technologies.

Most recently, the DOE announced a Long Duration Storage Shot as part of its Energy Earthshots Initiative. The goal is to reduce costs of grid-scale long duration energy storage within the next ten years by 90% for systems that can deliver more than 10 hours of energy. To achieve this goal, the DOE will hold a series of stakeholder discussions to evaluate the best approaches to accelerating research and development of this coveted resource.

Federal Energy Regulatory Commission

FERC is an independent agency within the DOE that regulates interstate transmission of natural gas, oil, and electricity. The Federal Power Act (FPA) provides FERC with authority to regulate the rates and service in the interstate transmission of electric power and wholesale sales of electric power. Pursuant to the FPA, FERC also reviews certain mergers, acquisitions, and corporate transactions and oversees compliance with reliability requirements, among other oversight activities. FERC also regulates the books and records requirements under the Public Utility Holding Company Act of 2005 and certifies and decertifies the status of "Qualifying Facilities" under the Public Utility Regulatory Policies Act of 1978 (PURPA). The Regulatory Compliance for Energy Storage section below provides an overview of some regulatory compliance obligations for ESRs.

FERC's policy on ESRs seeks to recognize the importance of this emerging and unique grid resource and to provide opportunities to integrate energy storage into wholesale power markets. Its review of the rules governing market design, market participation by ESRs, and interconnection to ensure that ESRs can efficiently interconnect with the grid, have access to markets, and receive a just and reasonable rate for their services continues. FERC regularly solicits public feedback through technical conferences, rulemakings, and policy statements and further opportunities for participation exist through the stakeholder processes administered by regional transmission organizations (RTOs) and independent system operators (ISOs).

Significant FERC Orders and Policy Statements Affecting Energy Storage

FERC has issued several orders and policy statements creating market participation opportunities for ESRs. This section provides an overview of those initiatives. Often when FERC issues these rulemakings, it will requires the RTOs/ISOs—ISO New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), and California Independent System Operator (CAISO)—and other regulated public utilities 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.

Recently, in July 2021, in FERC Docket No. RM21-17, FERC issued an advanced notice of proposed rulemaking regarding additional reforms to improve the electric regional transmission planning and cost allocation and the generator interconnection processes.

Significant FERC issuances are discussed below.

Expansion of Participation of DERs in RTOs/ISOs—Order No. 2222 (FERC Docket No. RM18-9)

In September 2020, FERC issued a landmark order aimed at removing barriers to the participation of distributed energy resources (DERs) in the regional markets for electric energy, capacity, and ancillary services operated 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 RTOs/ISOs-administered markets. Once implemented, Order No. 2222 is expected to further open up RTOs/ISOs markets to the benefits of competition and innovation.

Order No. 2222 defines 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 (such as ESRs) that can join DER aggregations.

Specifically, Order No. 2222 requires that DER aggregations meet a minimum size specified by the RTOs/ISOs 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. RTOs/ISOs compliance filings were originally due on 19 July 2021, but only CAISO and NYISO met that deadline. The other RTOs/ISOs received an extension, with their compliance filings now due in February 2022 (ISO NE and PJM) and April 2022 (MISO and SPP). As FERC provided the RTOs/ISOs with a large amount of flexibility in how they will implement Order No. 2222, each RTO/ISO, in their compliance filing, will have to demonstrate how its proposal complies with Order No. 2222 and propose a date on which the reforms will take effect in its markets. FERC will act on those filings and may order changes and subsequent compliance filings.

Order No. 2222 Compliance Filings Under Review

CAISO (FERC Docket No. ER21-2455)

On 19 July 2021 (the due date originally set by FERC), CAISO submitted its Order No. 2222 compliance filing. CAISO created a DER aggregation model in 2016 (the energy storage and distributed energy resources (ESDER) initiative), and its compliance filing states its current tariff already complies with the vast majority of the Order No. 2222 mandates. The proposed tariff revisions to align CAISO’s existing DER aggregation model with the requirements under Order No. 2222 include: (1) amending the definition of a DER to match the FERC definition; (2) providing an opt-out for small utilities; (3) implementing a DER aggregation model that includes both technologies that supply energy to load and that curtail demand (demand response); (4) creating a compliance obligation on the DER aggregation to avoid double counting with retail programs and requiring the distribution company and CAISO to confer regarding double-counting issues; (5) lowering the DER aggregation capacity requirement from 500 kW to 100 kW; and (6) requiring DER aggregators to notify the CAISO whenever their information changes due to the removal, addition, or modification of a DER within the DER aggregation. CAISO requested an effective date no later than 1 November 2022.

NYISO (FERC Docket No. ER21-2460)

On 19 July 2021, NYISO also submitted its Order No. 2222 compliance filing. NYISO likewise stated that its existing DER and Aggregation participation model complies with most of Order No. 2222. The proposed tariff modifications for compliance with the remaining directives of Order No. 2222 include: (1) addressing the interconnection of DER for the exclusive purpose of participating in an aggregation; (2) preventing the double-counting of DER services; (3) revising the market participation agreement for DER aggregations and DER enrollment requirements; (4) enhancing coordination among the NYISO, DER aggregators and distribution utilities; (5) requiring retail regulatory authorities to opt-in small utilities serving four million MWh or less per year to the DER program; and (6) revising the definition of aggregation to allow aggregations of a single resource. NYISO requested a FERC ruling on its compliance filing by 17 September 2021 so it can develop and deploy the required software changes for its DER and Aggregation participation model by its current target of Q4 2022.

Expanding Energy Storage Opportunities in Wholesale Markets—Order No. 841 (FERC Docket No. RM16-23)

In February 2018, FERC issued Order No. 841, which sought to remove barriers for energy storage participation in wholesale capacity, energy, and ancillary services markets in RTOs/ISOs.

Order No. 841 directed 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 ESRs. FERC mandated 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 or buyer.
- Account for electric energy storage's physical and operational characteristics (via bidding parameters or other means).
- Set a minimum size requirement for storage resources' participation in the RTO/ISO markets of not more than 100 kW.

In addition to these market requirements, FERC also determined that ESRs should pay the wholesale locational marginal price for electric energy that the resource buys from the RTOs/ISOs (presumably to charge the resource) that is then resold back into the RTOs/ISOs.

A number of stakeholder utilities and trade groups sought rehearing of Order No. 841, and later appealed FERC's rulings. 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 rulemaking and found that it does not run afoul of the FPA and "does not usurp state power. . . ."[1] 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. The appellate court upheld FERC's determinations and the appellate process is exhausted.

In December 2018, the RTOs/ISOs began filing tariff revisions to reflect their compliance plans for Order No. 841. FERC has largely accepted most aspects of the RTOs/ISOs compliance filings, but continues to drill down on specific nuances and aspects of how each 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 charges to ESRs for transmission and wholesale services, and charges for retail services. FERC has accepted the compliance filings from all RTOs/ISOs, and the compliance process is now completed. A description of individual RTOs/ISOs compliance filings and key takeaways is provided in the below RTOs/ISOs section.

Reform of Generator Interconnection Procedures and Agreements—Order No. 845 (FERC Docket No. RM17-8)

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* LGIA and LGIP 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

[1] 964 F.3d 1177, 1188 (D.C. Cir. 2020) (internal citations omitted).

ESRs because they will allow those resources to pair with existing generation with little or no additional interconnection costs.

In February 2019, FERC issued Order No. 845-A that clarified and revised aspects of Order No. 845. Relevant to energy storage, Order No. 845-A clarified 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 will analyze the impacts of storage projects using excess interconnection capacity of a different type of generation resource.

Policy Statement on Cost Recovery for Electric Storage Resources (FERC Docket No. PL17-2)

In January 2017, FERC issued a policy statement clarifying that an ESR may provide transmission or grid support services at a cost-based rate while also participating in the RTOs/ISOs 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.

Interconnection of Storage Resources Through Small Generator Interconnection Procedures—Order No. 792 (FERC Docket No. RM13-2)

In November 2013, FERC amended its *pro forma* Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA) to cover “storage for later injection of electricity.” The SGIP/SGIA applies to generating facilities and storage resources connecting to the transmission system 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/SGIA 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.

ESRs in Transmission Planning—Order No. 1000 (FERC Docket No. RM10-23)

ESRs are poised to play a greater role in transmission planning processes as “nonwire” alternatives. In July 2011, 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 as a “nonwire” alternative in transmission planning. Order No. 1000 has largely been considered a disappointment in facilitating transmission expansion.

Recent FERC Orders Impacting ESRs

FERC Concludes PURPA QF Size Limit Is Determined by "Send-Out" Capability Rather Than Nameplate Capacity (FERC Docket No. QF17-454)

In March 2021, in *Broadview Solar, LLC*[2], FERC reversed an earlier decision, and determined that a hybrid solar-plus-storage project met the requirements of a qualifying small power production facility (QF) pursuant to PURPA. Renewable facilities that have a maximum capacity, along with the capacity of affiliated same fuel source QFs within one mile (and potentially up to ten miles), of 80 megawatts of AC power (MWac) qualify as QFs. The Broadview Solar facility consists of a 160 MW solar component, and a 50-MW (200 MWh) battery storage component. However, the facility incorporated output-limiting inverters that constrained the facility to a maximum output at the point of interconnection of 80 MW, the ceiling to be eligible for QF status. FERC, on rehearing, concluded that the Broadview Solar facility indeed is eligible for QF status due to the "send-out" limitation of 80 MW. This ruling will assist hybrid resources, by allowing them to include storage to time-shift or extend production without disqualifying them from PURPA eligibility as a QF. But, FERC's *Broadview Solar* decision is currently pending judicial review in federal appellate court.

Storage Project Seeks to Provide Reactive Power Under PJM Open Access Transmission Tariff (FERC Docket No. ER21-864)

In January 2021, Meyersdale Storage, LLC (Meyersdale) submitted a proposed rate schedule for reactive power service in the PJM region. Reactive power services in PJM are paid at a resource's monthly revenue requirement which must be authorized by FERC. This was the first filing in which an ESR has sought to provide a rate schedule for reactive power service, and Meyersdale applied a methodology previously approved by FERC for more traditional generating resources, with a modified power factor to account for differences in a battery inverter. The PJM Independent Market Monitor challenged the filing on the basis that the power factor is extraordinary and questioned whether ESRs can provide reactive power service in compliance with the PJM tariff due to the lack of sustained output. FERC set these issues for hearing and settlement procedures, which remain pending, noting Order 841's requirement that ESRs be permitted to provide all services they are capable of offering.

FERC Denies Complaint Against NYISO on Buyer-Side Mitigation Rules for ESRs (FERC Docket No. EL19-86)

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 NYISO's capacity market and hinder governmental policy objectives. FERC found the complaint failed to meet the burden under FPA Section 206 to show that the NYISO mitigation rules were unlawful. 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."

On rehearing in October 2020, FERC affirmed its previous decision. FERC distinguished ESRs from "purely intermittent" renewable resources that are exempt from the mitigation rules, finding that the ESRs were not limited from participating in the capacity market and that the mitigation rules were not addressed or abrogated by Order No. 841 with respect to ESRs. FERC also determined that the

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[2] *Broadview Solar, LLC*, 174 FERC ¶ 61,199 (2021)

mitigation rules do not interfere with state authority over generation resources, because New York was free to promote chosen resources, but rather, the rules require that those resources "clear the capacity market on a competitive basis." Although FERC's decision is currently pending judicial review in federal appellate court,[3] and the New York Commission has requested that FERC reconsider its order or seek voluntary remand of the case back to the agency.

FERC Denies ESR Ability to Recover Cost-Based Rates as Transmission Asset (FERC Docket No. EL20-58)

In July 2020, utility American Electric Power (AEP) filed a petition for declaratory order, seeking for FERC to confirm that its 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, and PJM also took the position that the Middle Creek project qualified as a Transmission Facility, even though PJM is also still evaluating planning criteria for determining whether ESRs may be deemed a transmission asset and incorporated into the Regional Transmission Expansion Plan procedures through a stakeholder process. FERC considered whether the Middle Creek project "performs a transmission function," and concluded that it did not, because it served a function more analogous to a backup generator by providing power only to a subset of retail customers in an islanding mode during an outage. The fact that the project had cleared the PJM planning process and displaced the need for a looped transmission facility was inadequate, standing alone, to conclude that the project served a transmission function. Instead, FERC concluded the project would never discharge energy while connected to the transmission system, and no transmission in interstate commerce would occur. AEP's request for rehearing was denied in an 30 April 2021 order.[4]

FERC Finds ESRs Can Be a "Load-Shape Modifying Device" for Demand Response (FERC Docket No. EL20-15)

Ruling on a dispute over interpreting the terms of a full requirements power purchase agreement between North Carolina Eastern Municipal Power Agency and Duke Energy Progress, LLC, 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." FERC denied a request for rehearing in December 2020, and FERC's decision is currently pending judicial review in federal appellate court.[5]

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[3] N.Y. State Pub. Serv. v. FERC, No. 20-1496 (D.C. Cir. petition for review filed Dec. 14, 2020)

[4] Am. Elec. Power Serv. v. FERC, No. 21-1110 (D.C. Cir. dismissed May 19, 2021).

[5] Duke Energy Progress, LLC v. FERC, No. 21-1008 (D.C. Cir. petition for review filed Jan. 8, 2021).

INDEPENDENT SYSTEM OPERATORS AND REGIONAL TRANSMISSION ORGANIZATIONS

The FERC-jurisdictional RTOs/ISOs are public utilities that operate (but do not own) the transmission grid in large parts of the United States (as well as 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 markets for energy, ancillary services, and, in some cases, capacity, and through stakeholder processes, 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.

FERC has issued a number of rulemakings and orders establishing regionally organized markets. In 1996, FERC issued rulemaking Order No. 888 paving the way for the formation of ISOs to coordinate, control, and monitor the operation of the electric power system and facilitate open-access to transmission service. Later, in Order No. 2000, FERC promoted the formation of RTOs to administer the transmission grid on a regional basis throughout North America (including Canada). Today RTOs/ISOs regions cover a large portion of the continental United States, with individual utilities remaining responsible for grid administration outside of these areas. The RTOs/ISOs include PJM, CAISO, Southwest Power Pool, MISO, New York Independent System Operator, and ISO-NE. Offshore wind is principally being developed within the RTOs/ISOs footprint.

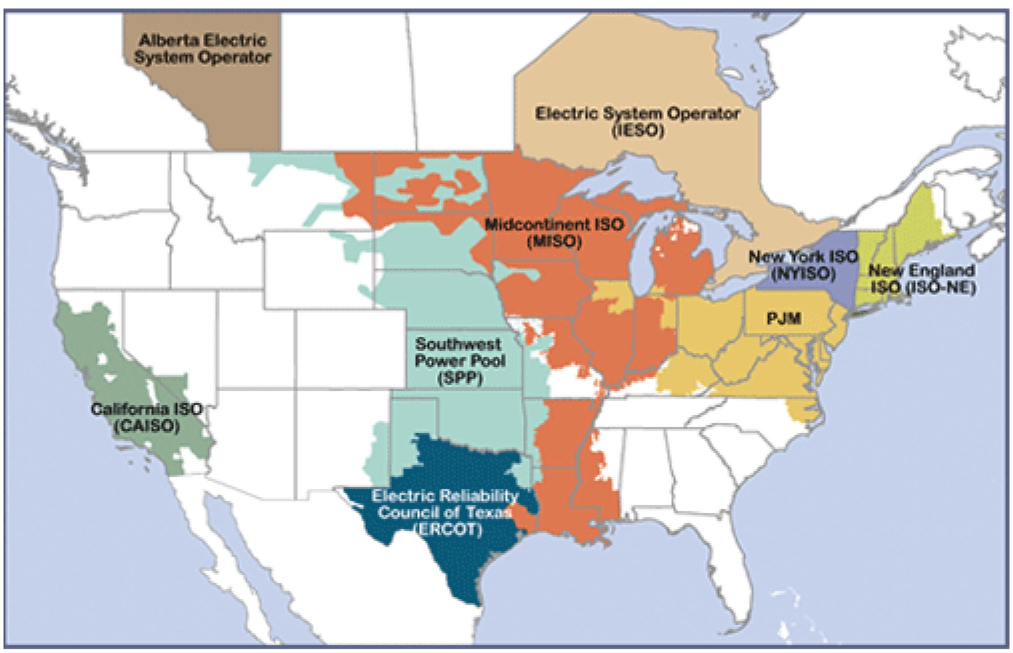

Figure 1 Source: https://www.ferc.gov/electric/power-sales-and-markets/rtos-and-isos

RTOs/ISOs are "public utilities" that operate (but do not own) the transmission grid. 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 storage, generation, and merchant transmission projects. RTOs/ISOs also dispatch (but do not own or operate) generation and other resources to meet the round-the-clock needs of electric energy customers. They operate competitive markets for energy, ancillary services, and, in some cases, capacity. Through stakeholder processes described below, RTOs/ISOs develop market rule proposals that are submitted to FERC to evaluate for compliance with the Federal Power Act. Like any other regulated public utility, RTOs/ISOs must put their tariffs (including market rules) and other agreements "on file" with FERC. To change a filed tariff or amend a filed agreement, the RTO/ISO must make a filing under Section 205 of the Federal Power Act and explain the reasons for the change. FERC typically acts on Section 205 filings in about 60 days. RTOs/ISOs also maintain manuals and other documents that set forth detailed procedures governing participation in the markets administered by the RTOs/ISOs. These materials are available on the websites of the RTOs/ISOs.

RTOs/ISOs have implemented orderly rules to facilitate participation by stakeholders in RTOs/ISOs governance. The importance of stakeholder participation in the RTOs/ISOs process cannot be understated; the stakeholder process is one of the primary avenues for the development of new market rules and tariffs and changes to the already "on file" market rules and tariffs. RTOs/ISOs stakeholders are grouped together in sectors representing major industry participant groups such as transmission owners, generation owners, electric distributors, end-use customers, other suppliers, and the like. RTOs/ISOs have numerous stakeholder bodies where members can bring forth issues for discussion. If the issue or proposal receives majority support, the members can vote to move the proposal through the hierarchy of the RTOs/ISOs stakeholder process up through Board review. Each participant sector is allocated a share of voting interests in the stakeholder governance process. In PJM for example, votes in the two senior standing committees, the Members Committee and the Markets and Reliability Committee, are recorded and weighted by sector to ensure that all interested parties are included in the decision-making process. PJM also has three standing committees that route endorsed packages to the senior committees for approval, as well as subcommittees, user groups, and task forces for preliminary issue identification and stakeholder discussion. Committed engagement in the stakeholder process, particularly at the subcommittee and standing committee levels, enables market participants to present proposals, identify issues, and shape market policies.

The California Independent System Operator

CAISO is one of the oldest RTOs/ISOs in the nation, responsible for managing about 80% of California's electricity flow. In collaboration with the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), CAISO has been at the forefront of considering ways to incorporate ESRs into California's wholesale electricity market. CAISO has more than 500 MW of battery storage on its system with an additional 1500 MW anticipated to come online by the end of 2021. More than 140,000 MW of stand-alone or hybrid battery storage is currently in the interconnection queue.

Starting around 2011 and in response to FERC Order Nos. 719 and 890, 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 and implemented participation rules for storage resources as part of its Non-Generator Resource (NGR) model. 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 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 has focused on streamlining market participation agreements for NGR participants. ESDER Phase 4 has culminated in tariff revisions that require ESRs participating in the NGR program to only execute a Participating Generator Agreement, and no longer need to execute a Participating Load Agreement. FERC approved the changes, with an effective date of 19 May 2021. Other changes to market rules adopted in ESDER Phase 4 include a default energy bid as a form of market power mitigation for storage resources, and optional end-of-hour state-of-charge bid parameters for real-time markets. These changes will be deployed in October 2021.

Order No. 841 Compliance Filings

Due in large part to this existing framework, CAISO did not need to make significant changes to its existing rules to comply with FERC Order No. 841. CAISO's compliance filings maintained its pre-existing rules for storage participation in its wholesale market with two key changes. Specifically, the filings: (1) lowers the minimum size for storage resources to qualify as participating generators and ancillary service providers from 500 kW to 100 kW and (2) exempts storage charging energy from transmission charges. Other changes clarify the metering and accounting aspects of CAISO's tariff to ensure ESRs are not charged both retail and wholesale rates while allowing ESRs to participate in both markets. ESRs are also permitted dual-participation in utility service territories where the utility refuses to track and net-out energy purchases from retail bills. More recently, FERC approved revisions to CAISO's tariff that allows CAISO to require ESRs providing resource adequacy to maintain a minimum state of charge under limited circumstances.

CAISO has also been a leader among the RTOs/ISOs in aggregating DERs, similar to what FERC Order No. 2222 calls for all RTOs/ISOs to implement. 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.

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 nearly 15,000 MW of stand-alone ESR capacity and another 18,000 MW of hybrid 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.

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.

In 2020, PJM and its stakeholders considered market reforms that would permit ESRs to be treated as transmission assets and to be integrated into PJM's regional transmission expansion planning process and created a special planning committee to investigate potential revisions to the PJM Operating Agreement that would allow such treatment. Phase one of this process was limited to consideration of storage's exclusive function as a transmission asset, and phase two would address dual-use capabilities of storage to also act as a market participant during periods in which it is not acting as a transmission asset. By December 2020, the special committee had developed proposed revisions that included a new definition of "Storage as a Transmission Asset (SATA)" and rules governing SATAs operational requirements and prohibitions, and criteria for their consideration as part of the regional planning process. The revisions received a majority of favorable votes in the special committee polling, but have been tabled until phase two is completed. The timeline for phase two is unclear at this time.

Most recently, PJM has included batteries as a category of resources that qualify for fast-start pricing by default. Fast-start resources operate in real-time markets and are able to respond quickly to system events, have a start-up time of less than one hour and a minimum run time of less than one hour.

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 Regulation A 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 interveners 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 nondiscriminatory 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 all issues, pursuant to which "Affected Battery Owners" will participate in the regulation market beginning July 2020 under specific terms and conditions agreed to in the settlement. The term of the settlement is 42 months. PJM 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. A rule change proposal, if filed by PJM, would not be submitted to FERC until after completion of the settlement term.

Order No. 841 Compliance Filings and Section 206 Proceeding

PJM made two separate filings that together constitute its participation model for ESRs, an "ESR Markets and Operations Proposal" and an "ESR Accounting Proposal." PJM's ESR Accounting Proposal allows PJM to test its proposed accounting methodologies and gather sufficient data before full deployment of the ESR Participation Model and revises the definitions of "Energy Storage Resource" and "Capacity Storage Resource." In February 2019, FERC issued a letter order accepting PJM's ESR Accounting Proposal, and which set the groundwork for PJM's second filing.

PJM's "ESR Markets and Operations Proposal" expands ESR and Capacity Storage Resource designations to include all storage technologies. PJM does not require pumped hydro storage resources to use the Order No. 841 participation model and resources that qualify for both models may elect participation under either model. ESRs will self-manage their state of charge.

Later compliance filings incorporated revisions that: (1) further described the three available operating modes for ESRs, (2) added bidding parameters for charge and discharge limits and ramp rates, (3) specify the services considered to be ESR dispatch, and (4) added general description and references for metering and accounting practices and revisions to describe how PJM would ensure separate accounting of wholesale and retail activities and clarifies that PJM would not charge ESRs for withdrawals when a distribution utility does not net-out charging activities from the retail bill. FERC approved the revisions in these compliance filings and made them effective December 2019, with certain revisions to be effective March 2024.

However, concurrently with its October 2019 order, FERC also opened an FPA Section 206 investigation to determine whether PJM's existing 10-hour runtime requirement for ESR participation in PJM's capacity market should be changed, an issue that FERC determined was beyond the scope of Order No. 841. FERC has since expanded the Section 206 proceeding to consider PJM's methodologies for determining the capability of all resource types for capacity qualification purposes. To address these issues, and with FERC's permission, PJM filed a new Effective Load Carrying Capability (ELCC) construct for determining capacity capability for resources such as ESRs that cannot maintain output continuously and without interruption on a daily basis. The ELCC analysis uses probabilistic modeling to evaluate a specific resource's system contribution based on reliability, size, and hourly output, updated annually to account for changes to resource mix, lead shape, weather patterns, and other factors. The new qualification amount would evaluate the resource's: (1) nameplate capacity, (2) ELCC Class Rating, and (3) ELCC Resource Performance Adjustment.

FERC initially rejected the ELCC proposal because it included a transition mechanism that would establish capacity floor values under a scenario that anticipated an antagonistic rather than synergistic resource mix. FERC determined this transition mechanism was unjust, unreasonable, unduly discriminatory, or preferential because it discounted capacity values of certain resources and increased the capacity value of others, resulting in capacity values that were above or below their actual capacity values. PJM submitted a revised proposal that removed the transition mechanism and defines the various ELCC classes. FERC accepted the revised proposal which became 1 August 2021. Under the ELCC, ESRs are no longer subject to a 10-hour minimum run-time.

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 5,600 MW of active requests associated with stand-alone ESRs and 4,800 MW of hybrid resources, as well.

Order No. 841 Compliance Filings

MISO's FERC Order No. 841 compliance filings provide for an ESR participation program that applies to all types of energy storage, including resources serving as non-wires alternatives to transmission and distribution needs as described more fully below. MISO has altered 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 designated time periods. Under MISO's program ESRs are able to manage the state of charge and ESRs that connect to the distribution system must execute a new pro forma Distribution ESR Agreement.

Later compliance filings include revisions that: (1) explained why ESRs are excluded from qualifying as fast start resources, (2) removed a proposed phase-in approach to permitting participation by very small ESRs, (3) removed transmission charges that would apply to ESRs dispatched to provide down ramp service, (4) provided additional specificity and revisions concerning metering and accounting practices for ESRs connected to the distribution system and behind the meter to prevent double-counting of retail and wholesale service charges and ensure ESRs may participate in both retail and wholesale markets, and (5) removed utilities' obligation to report ESR charging volumes.

Most recently in March 2021, MISO requested another extension of its implementation date, seeking to extend the date from 6 June 2022 to 1 March 2025. MISO stated the extension was needed to complete new system-wide software upgrades that would enable it to manage reliability with increasing solar and wind resources entering its system, and because the new ESR participation model software must be built on top of this new system, once operational. FERC denied the request and MISO's implementation date remains 6 June 2022. MISO is required to submit annual updates and explain whether it is able to implement its participation model sooner.

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 would pass through a designated market participant and serve to decrease the SATOA's revenue requirement. However, the SATOA will not otherwise be permitted to participate in MISO markets or in its voluntary annual capacity auctions.

Enhanced AGC Signals for Fast 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, which 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. There are more than 93 proposed energy storage projects in the NYISO interconnection queue, representing more than 11,500 MW of proposed capacity.

Order No. 841 Compliance Filings

NYISO's FERC Order No. 841 compliance filing created a new designation for ESRs as a subset of generators and revises 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. NYISO will also manage a battery's state of charge in the day-ahead market, rather than the ESR.

NYISO incorporated additional revisions in later compliance filings that: (1) create a process for ESRs to de-rate capacity to satisfy minimum run-time needs, (2) apply transmission service charges at times when the ESR is charging for later injection to the grid, but not when the ESR is providing a service, and (3) clarify that ESRs would still be subject to transmission charges when self-scheduled to withdraw fixed MW quantities. In October 2020, FERC accepted NYISO's final compliance filing and established an effective date of 26 August 2020 for NYISO's ESR participation model.

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 Co-Located Storage Resources

As part of a broader effort to address issues faced by hybrid resources, NYISO and its stakeholders worked throughout 2020 to finalize a proposal for a participation model accommodating co-located storage resources (CSRs). NYISO filed its proposal with FERC in February 2021, which was approved on 30 March 2021. NYISO is currently developing the market software necessary to accommodate the CSR rules, and expects to implement CSR in its markets by the end of 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. Each unit within a CSR will operate as two discrete generators, with each unit required 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. Distinct solar or wind and ESR projects currently being evaluated in the NYISO interconnection process, with separate positions in the interconnection queue, will be able to combine and proceed under a single interconnection request as a CSR. Generators participating in a CSR that NYISO studies together as a single project will have a single interconnection agreement, with each generator allocated Energy Resource Interconnection Services (ERIS) rights and Capacity Resource Interconnection Services (CRIS) rights separately, to be capped according to the physical limitation of the CSR.

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 has long operated pumped hydroelectric storage and about 20 MW of grid-scale battery storage has been interconnected since 2015. According to ISO-NE, another 3,000 MW of stand-alone ESR projects have joined its interconnection queue and a number of other projects in the queue incorporate ESRs.

Order No. 841 Compliance Filings

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. Under the 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. ESRs that are part of the Order 841 participation model are subject to central dispatch and accordingly, are at all times required to provide ancillary services and may be dispatched to cease charging at any time to address reliability concerns. 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 asserted it is inconsistent with Order No. 841. Other revisions by ISO-NE in compliance with Order No. 841 included changes that: (1) incorporate four new bidding parameters for State of Charge and Duration Characteristics in its day-ahead market that had previously only been included in the real-time markets, (2) included revisions that would assess transmission charges to ESRs that have self-scheduled to charge fixed MW quantities for any portion that is not used to provide a service to ISO-NE, (3) supplement and revise its metering and accounting practices to provide basic instruction and ensure ESRs do not pay twice for retail and wholesale charging energy, and (4) to ensure ESRs who participate in wholesale markets are not precluded from retail markets. ISO-NE will implement the majority of its participation model on 3 December 2019 with the State of Charge and Duration Characteristics terms to be effective 1 January 2026.

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 includes more than 13 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. In March 2021, the Committee recommended presenting revision requests to the SPP Board that would: (1) accredit storage capacity under an ELCC model, similar to PJM's current proposal discussed above, (2) create rules for hybrid resources, and (3) address storage as transmission only in the regional planning process, which will be modeled primarily on the MISO framework, also discussed above. The Committee is currently working through drafts of these proposed revisions, and these are the only revision requests anticipated in 2021.

Order No. 841 Compliance Filings

SPP's FERC Order No. 841 compliance filing provides a participation model for ESRs to participate in the market under the resource registration name Market Storage Resources and also allows ESRs to participate through existing participation models if they meet the requirements. ESRs may also fulfill Load Serving Entity resource adequacy requirements if the ESR meets the continuous run time requirement that applies to all resource types. Additionally, the ESR manages the state of charge. SPP has also incorporated revisions that: (1) define 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 and (2) remove certification provisions requiring ESRs to certify that they are not precluded by a retail regulatory authority from participation in wholesale markets.

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 became effective in August 2021.

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 stand-alone storage. Other bills have been introduced since, but currently there is no independent tax credit for stand-alone energy storage.

Tax Credits for Renewable Energy Property, Generally

Section 48 of the Internal Revenue Code (the Code) provides a 10% or 30% 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% 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%.

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% 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% 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).

Stand-alone storage does not currently qualify for the ITC, but legislation was recently introduced to create a new category of ITC for stand-alone 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,[6] 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, 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

[6] 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.

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% 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 stand-alone 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% 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% of a QOZB’s tangible assets must be located in one or more OZ areas.

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%. The gain may be further reduced by another five 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% by 2025 to 30% 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% of renewable energy by 2030 failed. ACC Commissioner Andy Tobin proposed a competing Renewable Portfolio Standard (RPS), Arizona's Energy Standard Modernization Plan in 2018, in which the state would have to meet an 80% clean energy target by 2050 coupled with a 3,000 megawatts thermal energy storage procurement target by 2030. However, this initiative also failed.

More recently, ACC has had some success. In November 2020, ACC proposed new energy rules that would require that there be installed energy storage systems by December 2035 with an aggregate capacity equal to or greater than five percent of an electric utility's 2020 peak demand, 40% of which must be customer-owned or leased distributed storage. The rule further provides that utilities must submit tariffs and programs to incentivize customers to purchase or lease distributed storage in exchange for that customer's participation in a demand response or similar program, as well as to provide compensation to customers for the energy storage value stack. In 2019, as a benefit to residential storage owners, the ACC further adopted an expedited interconnection process for non-exporting energy storage devices that are less than 20 kw.

Outside of the REST rule and related proceedings, 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 two 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 2020 Integrated Resource Plans, with TEPCO's calling for 1.4 GW of energy storage capacity over the next 15 years to accelerate the retirement of coal power plants. In January 2018 TEPCO issued a Request for Proposal (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, and in early 2019, APS issued additional RFPs for another 200 MW of battery storage to be added to six existing solar farms. Also in 2019, APS contracted with First Energy to construct a solar-plus-storage facility with 65

MW of solar, and a 50 MW battery component. In December 2020, APS issued another RFP requesting a total of 60 MW battery storage to retrofit existing solar facilities.

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 four 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. In 2018, APS 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 enacted 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.

In October 2020, ACC approved of a residential energy storage pilot program proposed by APS. The program offers incentives in the amount of US$500 per kilowatt of installed storage, with a maximum incentive of US$2,500 for APS customers. Originally, the program had proposed only a US$300 per kilowatt incentive, but a greater incentive was deemed appropriate to drive greater adoption of energy storage by residential customers within the state. As an additional incentive, grandfathered net metered solar rooftop customers remain grandfathered if they install storage under the program. APS is also required to submit a revised tariff in early 2021 to provide for aggregation of distributed energy storage resources to provide compensation for the value stack of benefits these resources will provide to the grid.

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 CEC, and the 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% 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 subarea'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's (PG&E) 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 expensive 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 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 stand-alone 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 Senate Bill 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% 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 Senate Bill 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, Senate Bill 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, Senate Bill 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% of total funds are exhausted. Eighty percent of funds are allocated to energy storage technologies, of which 87% are allocated for projects greater than 10 kW in size, and 13% are allocated to the existing carve-out for residential energy storage projects less than or equal to 10 kW in size. The remaining 20% of funds are available for renewable generation technologies. Any single developer/ installer is limited to 20% 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 toward incorporating energy storage into the state's electric grid. First, in March, Governor Hickenlooper signed Senate Bill 9 that directed the Colorado Public Utilities Commission (Colorado PUC) 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. The Colorado PUC commenced a rulemaking proceeding in October 2019 to incorporate new interconnection standards that address energy storage facilities, and that proceeding remains ongoing with new rules anticipated to be finalized in early 2021.

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 November 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. Pursuant to these requirements, in October 2020, Colorado PUC approved of Public Service Company of Colorado's application for rate base treatment of six MW of energy storage as part of a community resilience initiative that will be sited at seven discrete community locations where enhanced energy security and safety is desirable. Black Hills Energy has also recently obtained PUC approval to include as part of its electric resource plan authorization for up to 200 MW procurements of renewable energy and energy storage.

Another issue that has been raised with the Colorado PUC is whether energy storage projects may qualify for funding pursuant to the Renewable Energy Standard Adjustment program, a cost recovery program directed at implementing Colorado's renewable energy standards. In a 2020 decision, PUC concluded that, currently, energy storage does not qualify as an "eligible energy resource," but nevertheless, energy storage systems would qualify to the extent they would be considered directly related interconnection facilities of clean energy resources.

Connecticut

Connecticut very recently passed legislation in 2021, Senate Bill 952, that targets 1,000 MW of energy storage by 31 December 2030. The bill provides interim targets of 300 MW by 31 December 2024 and 650 MW by 31 December 2027. In order to reach these targets, the Connecticut Public Utilities Regulatory Authority (CT PURA), in coordination with various other state agencies, is required initiate a proceeding by 1 January 2022 to develop programs and funding mechanisms for energy storage deployment on the distribution system. Separate programs must target (1) residential customers, (2) commercial and industrial customers, and (3) ahead-of-the-meter storage systems. In developing the appropriate funding mechanisms, CT PURA is to investigate rate designs and other incentives that most effectively leverages the benefits of energy storage to achieve various objectives such as (1) net present value, (2) grid benefits such as resiliency, ancillary services, peak-shaving, and support of other distributed energy resources, (3) state storage industry development, (4) capacity market revenues, and (5) deferral of distribution system upgrades.

SB 952 further permits the Connecticut Department of Energy and Environmental Protection (CT DEEP) to administer an RFP procedure for the selection of cost-effective energy storage projects. CT DEEP is first required to establish a cost-effectiveness test that considers: (1) rate implications, (2) reliability benefits, (3) economic development within the state, (4) greenhouse gas emissions, and (5) the state's Comprehensive Energy Strategy and Integrated Resources Plan. These projects can be either stand-alone storage or co-located with Class I renewable resources. The regulated utilities would be the contract counterparties, and each utility's costs and revenues would be passed on to ratepayers through a reconciling rate component.

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% 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% renewable electricity when it passed a law directing the state's utilities to generate 100% of their electricity sales from renewable energy resources by 2045. Hawaii's 100% 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.

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 stand-alone 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 stand-alone storage project totaling approximately 100 MW of generation and 560 MWh of storage on Maui Island, and two solar-plus-storage projects and one stand-alone storage project totaling approximately 72 MW of generation and 492 MWh of storage on Hawaii Island. HECO plans to couple grid services and nearly three 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.

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% of annual retail electricity sales (increasing annually to reach 16.5% by 2030 and 46.5% 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% 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% 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% 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.

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.
- 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 remains one of the most aggressive energy storage targets 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% 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 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.

BPU has yet to propose or approve financial incentives for energy storage installations in order to meet the 2021 or 2030 targets. In a September 2020 order approving funding for clean energy programs during the fiscal year 2021, BPU allocated US$7 million toward meeting the state's energy storage goals. As part of this same order, BPU Staff indicated that a straw proposal on energy storage would be forthcoming, but no such straw proposal has yet been released, and it remains unclear how these funds may be used to incentivize energy storage within New Jersey. In October 2018, Public Service Electric and Gas Company (PSEG), New Jersey's largest electric distribution company, submitted a petition proposing US$180 million of energy storage development to install 35 MW of energy storage over a period of six years. This energy storage program is being held in abeyance pending completion of BPU's stakeholder process.

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, New York, in September 2019. A 2019 New York Public Service Commission study concluded that 230 MW of the state's peak generation fleet, or about six 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

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 five MW in capacity or greater and US$130 million for storage projects that are smaller than five 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 five 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 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 solarplus-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 Senate Bill 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% of the time during peak summer hours, instead of the 29.9% average of Nevada solar plants. It will also assist in meeting Nevada's newly passed renewable portfolio standard of 50% renewable-generation by 2030 and 100% by 2050. NV Energy believes that based on its current project pipeline, it will—standing alone—exceed the one GW target by 2024, far earlier than the 2030 goal.

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.

PUCN has also approved of incentive programs for non-utility-owned energy storage systems, large and small. NV Energy's program provides incentives based on the watt-hour capacity of the system, with a cap of US$3,000 for small systems. Different rates apply depending on whether the system is eligible for the federal investment tax credit, and for large systems, whether the system is critical infrastructure or not. However, despite being required to set aside US$10 million for this program, it has seen little interest, and only a small fraction of that funding has been used.

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% 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% 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 Electric Delivery Company's advanced microgrid incorporating 25 kW of community energy storage systems; E.On North America'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 Senate Bill 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 a 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 Abbott signed Texas SB 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.

Electric Reliability Council of Texas

ERCOT is the regional entity responsible for operating the transmission grid and energy-only wholesale markets in most of Texas. ERCOT, unlike the RTOs/ISOs discussed above, is not subject to the general jurisdiction of FERC and instead is subject to regulation (including rate regulation) by 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.

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% 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 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 gasifired peakers. The UTC also made clear that it would apply ordinary cost recovery mechanisms to IOU acquisition of ESRs.

In May 2019, Washington enacted Senate Bill 5116 which mandates that the state obtain 100% of its electricity from non-fossil sources by 2045. The law requires utilities to consider energy storage in its resource planning. UTC adopted rules incorporating these requirements in January 2021. Utilities must now consider energy storage within their resource adequacy analyses. In fashioning the rules, UTC declined to adopt prescriptive elements of the resource adequacy modeling and assessment in a fashion that would be more particularly tailored toward the characteristics of certain resources, such as batteries, and instead will rely on the more generalized prudency principle in reviewing these plans, which it determined to be a more flexible approach long term.

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 five 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.

PSE’s 2021 IRP includes a preferred portfolio of battery storage resource additions of 75 MW between 2022–2025, another 125 MW by 2030, and then 550 MW more by 2045, but in a 100% renewable scenario, could reach as high as 26,100 MW capacity by 2045. Avista’s most recent IRP demonstrates large generator interconnection requests for solar + storage projects that together exceed 660 MW to be completed by December 2022, another 500 MW project in 2024, and a 500 MW stand-alone storage project in December 2023, though Avista’s preferred plan would not include additional utility-owned storage systems until 2038, a change in position from the 2020 IRP that anticipated much earlier investment.

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 energy storage projects shares similarities with financing solar and wind projects. Investors and lenders prefer projects with long-term offtake agreements, reliable technology, and creditworthy counterparties (or backstop assurances, like performance assurance).

Beyond these fundamental similarities, however, energy storage projects are inherently more complex than solar and wind and typically face several additional types of challenges when 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 RegD 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 particular features, several forms of agreement generally in use are summarized below.

Energy Storage Tolling Agreement

California utilities pioneered the use of Energy Storage Tolling Agreements (Tolling Agreement) 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 Service Agreement

Under a Capacity Service Agreement (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

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 Demand Response Energy Storage Agreement (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% 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 commercial and industrial energy storage 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 nonperformance. 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 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 stand-alone 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 nongovernmental 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 stand-alone 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 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 risks of blaming the counterparty for non-performance can be mitigated with detailed 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%.

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 Agreements

The best way to avoid expensive litigation over unexpected problems with the construction, delivery or performance of a BESS is clearly to allocate as many of these risks as possible in the EPC or BESS supply contract. As the industry has matured, such contracts have come to better define and allocate the major risks inherent to large-scale grid-connected battery deployment. Nevertheless, in any battery storage contract, parties must pay careful attention to critical risk allocation provisions. Even then, if an unexpected event happens that disrupts contract performance, the parties need to follow best practices to communicate with counterparties, protect their legal position, and effectively pursue commercial solutions.

This section addresses three ways that parties can avoid potential litigation in the battery storage context. First, we look at ways to allocate the risks of supply chain disruptions to avoid disputes over related delay damages and materials cost increases. Second, we provide drafting guidance to avoid disputes over battery performance or degradation issues, including tips for defining the batteries' use case, operating parameters, and minimum performance requirements while also avoiding surprises in liquidated damages or warranty obligations. Finally, we briefly outline best practices when a breach occurs to reduce the likelihood of litigation.

Addressing Supply Chain, Construction, and Delivery Risk—Force Majeure

The global pandemic has highlighted the need to pay special attention to supply chain risk. This is especially true with battery storage projects where supply chain disruption could result in an inability to obtain required lithium ion batteries or other key components such as inverters or electrolyte for flow battery plants. Even if the pandemic ultimately subsides, supply chain risk will continue to be endemic to battery storage projects given the predicted continued scarcity of grid-scale lithium ion batteries.

Avoiding disputes caused by supply chain disruptions requires parties realistically to assess the risk that batteries or other key components will be unavailable or dramatically more expensive, and clearly allocating those risks in the relevant agreements. A key contractual provision in this regard is the force majeure clause. In drafting force majeure clauses, the parties should carefully consider:

- Is the definition of "force majeure event" in line with the parties' expectations? Force majeure events may be defined narrowly or broadly. For instance, they may be strictly limited to enumerated events, such as famine, flood, or government lockdown orders in a pandemic. Alternatively, the parties can include a catch-all provision defining them as any unforeseeable event that renders a party's performance at least temporarily impossible.

- When does the force majeure clause relieve a party of its duty to perform? Many force majeure provisions only relieve a party of its performance obligations if the event renders performance "impossible" or "illegal." Some clauses contain lesser thresholds, for instance requiring only that the event renders performance "impractical" or "commercially unreasonable." This language is a key aspect of allocating risks that a major battery storage component might increase dramatically in price due to government lockdown orders or other force majeure events.

A force majeure clause alone, however, may not be sufficient to anticipate and allocate supply chain risk. In most cases, for force majeure to relieve a party of performance, the force majeure event must have been "unforeseeable." Many supply chain risks are foreseeable, such as demonstrated delays in delivery from a battery or component supplier due to raw materials or microchip shortages.

The parties should therefore seriously consider having separate provisions that will dictate which party is responsible for bearing the increased costs of components or batteries, or the cost of delayed performance. The goal is to avoid a situation where it is unclear which party must bear the cost of dramatically increased component prices or delivery delays, which can lead to litigation.

BESS delivery deadlines are another instance where the parties must take supply chain risk into account. Most EPC or BESS supply contracts contain detailed delivery and operational deadlines and corresponding liquidated damages provisions if those deadlines are not met. Parties should carefully review these provisions to ensure that they correctly allocate risk in the event that performance is delayed due to unforeseen or unavoidable supply chain issues for batteries or other key plant components.

Defining Use Case, Specifications, and Performance Requirements

Once a BESS is commissioned and operational, the contractual requirements concerning battery performance and longevity requirements come into play. Avoiding disputes at this stage requires clear and unambiguous provisions stating how the plant is guaranteed to perform, the use case and parameters under which such performance is promised, the liquidated damages that will be paid if performance guarantees are not met, and the available warranties requiring repair or replacement of defective components or prematurely degrading batteries. While battery suppliers, integrators, operators, and their attorneys have all become more adept at avoiding ambiguity in these provisions, there are still lessons to learn from litigation over older contracts where uncertainty created by ambiguous language led to contentious disputes.

Use Case

Lithium ion battery performance is inevitably tied to the demands that a particular deployment will place on those batteries. Parties should therefore contractually define the particular use case or cases for a BESS and limit performance guarantees or degradation warranties to those use cases. For instance, if a BESS is expected to be used in an application where it is rarely expected to charge or discharge for extended periods at maximum power, or where its state of charge can be maintained within battery-friendly parameters, the performance guarantees and degradation warranties in the contract should be contingent on that specified use case. Absent clear use case definitions, disputes can arise as to whether performance guarantees (and related liquidated damages) still apply where the use case or operating parameters have changed.

Regulatory Framework

Related to use case definition are provisions that address the allocation of regulatory risk. As noted above in the section discussing financing risks, a risk for any gird-connected battery storage project is regulatory volatility. Unforeseen regulatory changes can not only upend the parties' pricing or revenue expectations, but can also result in unexpected changes to the operating demands placed on the batteries. An example is PJM's modifications to regulation frequency dispatch signals in 2016 that dramatically increased battery throughput, which in turn tends to increase battery operating temperatures and speed capacity degradation. 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 to the extent possible.

Application vs. "Nameplate" Specifications

In the past, some BESS supply contracts incorporated both application-based performance requirements and "nameplate" performance requirements into the contractually promised specifications. For an example, the contract might 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 raises uncertainty 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. This kind of uncertainty can lead to litigation in the event that unexpected demands are placed on the battery technology.

Exclusivity of Remedies and Limitation of Liability

In EPC and other battery plant supply contracts, it is common practice for the 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.

As a foundational matter, 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 an expensive surprise to the BESS supplier or integrator.

Parties can avoid these situations by clearly 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 (presumably subject to an agreed-upon liquidated damages cap).

Warranty

The warranty in a BESS allocates 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.

- It is therefore important to incorporate these key considerations or provisions: 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.

- All current lithium ion 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 define carefully the limit unambiguously. For instance, a reference to maximum charge or discharge cycles should spell out what the parties mean by cycle. The limit should also be consistent with the defined use case or cases for the system.

- 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 if that operating temperature range is irrelevant to the anticipated use cases.

- Consistent with use case considerations for performance guarantees, 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, be consistent with the defined use case for the system and should be voided by use or operation inconsistent with the specified use case.

- 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 a performance guarantee or other liquidated damages provision designed to mitigate the purchaser's financial losses from equipment defects or plant underperformance, the contract should explicitly address additional key issues:

- At least in the United States, state law generally imposes limits on liquidated damages (LDs). Typically, for a LDs 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 LDs have to have a reasonable relationship to or be a reasonable estimate of actual damages. Applying this rule, the parties should draft LDs 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 or integrator may otherwise lack access to battery performance or market revenue data on which LDs calculations are based.

- Since no battery supplier or integrator 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 not appealable, 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.

Best Practices in the Event of a Supply Chain Disruption

Even if the parties to an energy storage EPC or supply contract successfully allocate supply chain risk in force majeure and similar provisions, an unexpected supply chain issue can still lead to litigation if the parties do not deal with it appropriately. An unavoidable breach of a battery supply or EPC contract can be a stressful time for both the party that is unable to perform and the party that will be deprived of the benefit of timely performance. Despite the natural inclinations to wait and hope that the problem will resolve itself, parties are better served by addressing the issue promptly and thoughtfully, with the advice of experienced counsel. A few best practices and considerations when a breach occurs:

- Define the event and consider force majeure. In the event of a supply chain disruption, the breaching party should immediately conduct a legal analysis the force majeure and similar provisions in the operative contract that might excuse performance. The key steps are to define the unexpected event that has led to non-performance and, determine whether it falls within a listed force majeure event or "catch all" provision.

- Notice requirements. Force majeure provisions often require a breaching party to provide notice of the force majeure event within only a few business days. If there is any possibility that force majeure might excuse performance, the non-performing party may want to err on the side of providing timely notice of the potential force majeure event.

- Communication strategy. As difficult as it can be to convey bad news to a counterparty, prompt communication is often essential to avoiding expensive litigation or arbitration. Providing timely notice that an unavoidable and unexpected event has occurred and the plan to mitigate any delay or damages can open positive dialog that can lead to successful commercial resolutions. A failure to timely communicate can lead to mistrust and escalating disputes.

- Mitigation. In most circumstances, state law will require parties to mitigate damages stemming from a breach. For instance, a party may need to "cover" the impacted performance, even if the cover solution is more expensive than the contract price (for instance purchasing alternative batteries at an increased cost). On the other side, a supplier that cannot obtain required batteries or other materials from the anticipated source may still be required to perform if another supplier is available, even if performance is more costly. The specific terms of the contract should dictate more precisely when performance is still required and to what extent.

- Be conscious of statements that might affect other commercial celationships. Where supply chain issues arise, parties must always be aware of how their position as to one contract might affect other contract relationships. For instance, a declaration of force majeure by an integrator under an EPC contract may make it difficult to challenge a force majeure declaration by the downstream supplier of batteries or other components to the integrator.

- Develop and protect your legal position. While prompt and open communication with counterparties can often calm initial litigious impulses, it is also important for all parties to protect their legal position in case attempts at a commercial resolution fail. This generally involves exercising caution in communications with counterparties, while thoroughly documenting the force majeure event, its effects on the business, and related mitigation efforts. For the party damaged by the non-performance, it means keeping detailed records of the damages caused by the delayed or cancelled performance.

- Address insurance issues. Any time that an unexpected event leads to potential exposure for breach of contract, parties should examine any relevant insurance policies and consult with relevant brokers to determine if there might be coverage. This will also assist to ensure that timely notice is provided to any insurers.

Avoiding Litigation When Performance Issues Arise

Many of the same best practices in the supply chain disruption context also apply in the event of unexpected performance or degradation issues. As with supply chain disruptions, prompt and thoughtful communication about performance issues and possible remedies can lead to successful commercial solutions that minimize the parties' damages and avoid disputes.

- Analyze the contract. The party that first becomes aware of apparent performance problems should conduct an initial analysis of the contract language to determine how it allocates responsibility for damages and repairs. Careful attention should be paid to performance guarantees, liquidated damages provisions, and warranty obligations.

- Communication plan. As with supply chain problems or construction or delivery delays, prompt and thoughtful communication between counterparties concerning BESS performance issues, their causes, and possible remedies can begin a dialog that will minimize disputes over the parties' obligations and facilitate commercial resolution instead of litigation. Prompt communication can help the parties confirm that a performance issue really exists, its cause, the appropriate calculation of associated liquidated damages, and required warranty repairs or battery replacements.

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

Interconnection procedures will vary depending on which utility, or RTO/ISO, the project is seeking to interconnect to, whether the project is seeking to utilize surplus interconnection service with an existing project or start a new stand-alone or co-located interconnection, whether the project is seeking to interconnect to the transmission system (generally under the jurisdiction of FERC) or the distribution system (generally under the jurisdiction of the state), whether the project is seeking to interconnect behind the customer meter, whether the project is seeking capacity (as opposed to energy only) attributes, and whether the project is pursuing a PURPA power purchase agreement and interconnection. Energy storage projects generally undergo the same applicable interconnection processes as generation resources.

At the end of the interconnection study process, and based on the interconnection procedures used, the ESR will generally receive a standard form interconnection agreement (with project details contained in the appendices to the agreement) that will govern the connection to the grid.

Interconnection Timing

Especially for utility-scale ESRs connecting to the transmission system, interconnection can be a long lead-time item. For many utilities and RTOs/ISOs, the FERC-jurisdictional process may take years between when an interconnection request is first submitted and a project receives its interconnection agreement. For small projects or behind the meter projects, there may be fast-track processes available to expedite the interconnection process.

Due to large interconnection backlog, many utilities and RTOs/ISOs have recently made revisions to their FERC-jurisdictional interconnection procedures to attempt to speed up the process. These reforms include:

- Cluster queue study process. Traditionally (especially outside of the RTOs/ISOs), FERC-jurisdictional interconnection requests have been processed on a first-come, first basis (with interconnection requests submitted earlier having priority over interconnection requests submitted later in time). Under a cluster queue study process, the utility generally sets a limited time period each in which it will accept interconnection requests, and all interconnection requests submitted during that time period will be studied together and given the same interconnection queue priority. In addition, projects included in an interconnection cluster need to meet certain milestones before it can proceed to each phase in the interconnection study.

- Earlier showing of site control. Traditionally, interconnection customers could avoid having to demonstrate site control when it submitted its interconnection request by submitting an additional US$10,000 deposit. But, some utilities now require an interconnection customer to demonstrate site control when they submit their interconnection request. In addition, the FERC pro forma interconnection procedures now require that site control be demonstrated by the time the interconnection customer signs the interconnection system impact study agreement (the second study in the interconnection processing).

- Demonstration of readiness milestones or increased financial commitment. Traditionally, an interconnection request could start an interconnection request by only providing a US$10,000 deposit. Some utilities now require that interconnection customers must also demonstrate that they have satisfied a readiness milestone (such as executing a power purchase agreement) or provided an increased financial deposit in order to submit an interconnection request.

- Financial penalties. Some utilities now impose financial penalties for withdrawal after an interconnection request is submitted.

During the FERC-jurisdictional 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) the applicant acted 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. It is important that interconnection customers understand and comply with their interconnection deadlines. FERC has denied waiver requests for ESRs in PJM when the interconnection customers misunderstood (and therefore missed) a financial security deadline and did not timely follow-up with PJM.

Interconnection Costs

The cost responsibility for interconnection facilities and upgrades necessary to accommodate the interconnection of the ESR will vary according to the applicable interconnection procedures and interconnection agreement. Under many FERC-jurisdictional interconnection agreements, the interconnection customer is responsible for the costs of all of the interconnection facilities and upgrades necessary to connect the project to the grid (although the costs of the upgrades would be reimbursed to the interconnection customer through transmission credits).

Although interconnection customers are generally responsible for the costs of the upgrades necessary to accommodate the interconnection of their projects, there is currently a push by transmission owners in the RTOs/ISOs to allow a transmission owner to elect whether or not to fund the required network upgrades. In the case of initial transmission owner funding of the network upgrades, the interconnection customer would then have to provide reimbursement to the transmission owner for the construction costs plus a predetermined rate of return for the transmission owner. This is currently the policy in MISO, and transmission owners in NYISO have a pending petition before FERC to institute a similar policy in its region.

Surplus Interconnection Service

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 interconnection service allowed under the existing interconnection agreement will require a brand new interconnection request. However, under FERC-jurisdictional interconnection agreements, an ESR can use surplus interconnection service to add an ESR to an existing generation capacity (provided that the total MW of interconnection service does not increase). While the transmission provider will still need to study the proposed surplus interconnection service, it should be a more limited and expedited process than submitting a new interconnection request.

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 or existing interconnection agreement. 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 perform reliability evaluations based on the capacity specified in the interconnection request or the existing interconnection agreement, which may be less than the device's maximum capacity.

REGULATORY COMPLIANCE FOR ENERGY STORAGE

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 Regulatory Compliance

Federal Power Act

FERC regulates transmission and the wholesale sales of energy in the continental United States (outside of the ERCOT region in Texas) pursuant to the Federal Power Act (FPA). Prior to making any wholesale sales of electric energy, capacity and/or ancillary services (including sales of test energy), a project company must receive from FERC either market-based rate authorization or cost-based rate authorization under FPA Section 205 or be exempt from rate regulation by FERC. Note, any retail sales (i.e., sales to end users) of energy, if regulated, would be under the jurisdiction of the relevant state public utility commission where the project company would make such sales.

An ESR will likely have to obtain market-based rate authorization to participate in the wholesale markets. It is important that the ESR receive market-based rate authority before it makes any wholesale sales, including test sales (as sales made without the necessary authorization will be subject to refund by FERC). To obtain market-based rate authorization, a project company will have to apply to FERC and demonstrate that it (and its affiliates) do not have, or have adequately mitigated, horizontal and vertical market power. FERC has 60 days to rule on a completed market-based rate application. As the name implies, a project company with market-based rate authority is expected to charge rates that would be expected in a competitive market and to comply with the market rules in the relevant tariff. In this regulatory framework, FERC does not prescribe the individual rates it can charge for its wholesale sales of electric energy, capacity and/or ancillary services.

Once a project company has market-based rate authorization, it will be subject to general FERC regulation as a "public utility." As a FERC-jurisdictional "public utility," the project company will, among other regulations, be required to file electric quarterly reports with FERC detailing its power sales and contracts, to report to FERC changes in the information contained in its market-based rate application, and to obtain FERC approval under FPA Section 203 prior to certain changes in upstream ownership. A project company will have market-based rate authority until such authorization is cancelled (either upon application of the project company or by FERC on its own initiative for non-compliance with the FPA regulations). The specific requirements for obtaining and maintaining market-based rate authority (as well as other requirements applicable to FERC-jurisdictional "public utilities") may change, so it is important to confirm the applicable requirements. For example, FERC recently launched its new market-based rate relational database in which all market-based rate sellers are required to make a baseline submission.

In addition, certain RTO/ISO markets (including capacity markets) have extensive rules governing participation and market monitoring. It is important that an ESR comply with all applicable rules in the markets in which it participates, as both the RTO/ISO and FERC Enforcement may seek to enforce compliance with such market rules. A FERC Enforcement investigation can lead to civil penalties and disgorgement of profits, as well as other consequences.

Public Utility Regulatory Policies Act of 1978 and Qualifying Facilities

Renewable facilities (such as wind or solar generation) with a net aggregated power production capacity of 80 MWac or less qualify as qualifying facilities (QFs). Stand-alone ESR does not qualify as QFs (since the fuel source of a grid-charged ESR is not considered renewable). But, if an ESR is co-located with, and solely charged by, a renewable project, it can qualify as a QF. As summarized in the above discussion of FERC's recent Broadview Solar decision, a co-located renewable plus storage project is currently considered by FERC to be one QF with its output limited by the level of interconnection service. In addition, when determining the size of the QF, FERC will include the net power production capacity of the project, as well as the net power production capacity of all affiliated same fuel source projects within one mile (and potentially up to 10 miles) of the project.

For a project with a new power production capacity over one MWac to become a QF, the project company needs to file a Form 556 Certification of Qualifying Facility status with FERC. The project company also needs to file a recertification of QF status when information reported on the Form 556 changes.

QFs with a net aggregated power production capacity of 20 MWac or less are exempt from most FERC regulation (including rate regulation under FPA Section 205). QFs with an aggregated net power production capacity over 20 MWac are subject to rate regulation by FERC (including the need to obtain market-based rate authority). In addition, utilities are required (unless their purchase obligation has been terminated) to purchase the output of a QF (although recent PURPA reforms allow utilities in RTOs/ISOs apply to FERC to terminate their purchase obligation for QFs over five MWac).

Public Utility Holding Company Act of 2005 and Exempt Wholesale Generators

FERC has also implemented accounting and record keeping regulations pursuant to the Public Utility Holding Company Act of 2005 (PUHCA). If the project company will be exclusively engaged in making wholesale (and not retail) sales of energy from the ESR, the project company can file a self-certification of exempt wholesale generator (EWG) status with FERC and become exempt from most of FERC's PUHCA regulations. 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.

In addition, if the ESR is a QFs with an aggregated net power production capacity of 30 MWac or less, it will also be exempt from most of FERC's PUHCA regulations. There also PUHCA exemptions available for holding company system that operate primarily in a single state.

NERC Reliability Oversight and Compliance

In addition to market and rate regulation, FERC oversees the reliability of the bulk power system. FERC has delegated to the North American Electric Reliability Corporation (NERC) the authority to create and enforce reliability standards for the bulk power system. NERC, through its six regional entities, registers certain owners, operators and users of the bulk power system. The NERC registration criteria and reliability standards are geared towards generators (as opposed to ESRs), but NERC concluded in a February 2021 study that existing NERC reliability standard adequately reflect battery storage as a generator. If an ESR meets the criteria for registration (either on its own or with a co-located generation project) or is otherwise identified as having a material impact on the bulk power system, it will be registered by the applicable NERC regional entity and be required to comply with the reliability standards that apply to its registered functions. Once an ESR is registered, failure to comply with the NERC reliability standards can lead to enforcement action (including penalties and other mitigation measures).

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 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 nonperformance.

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.

Battery Reuse and Recycle

On 24 February 2021, the Biden Administration issued an Executive Order on America’s Supply Chains to develop more resilient, diverse, and secure supply chains for critical and essential goods. The Executive Order was driven by a need to close supply chain vulnerabilities across a range of critical products on which the United States is dependent on foreign suppliers. The Executive Order recognizes the importance of developing sustainable energy infrastructure and identifies (1) high-capacity batteries, including those used in electric vehicles, and (2) critical rare-earth minerals and materials as high-priority areas requiring future investment and resources.

Over the last two decades, we have seen substantial progress made with respect to the development, use, and commercial application of lithium ion batteries, including advances related to the equipment, components, and materials used to make them. There has also been significant investment in the infrastructure necessary to adopt and normalize the use of battery technologies on a commercial-scale. However, with wide-spread commercial adoption comes increased demand.

In the next decade, the demand for lithium ion batteries and the materials used to make them are estimated to increase between 1500% and 1800%. This unprecedented demand will stress the supply chain infrastructure for lithium ion batteries and the materials used to make them. There are already a number of private companies looking to address this increased demand and minimize the impact from potential shortages. Among these companies are a number proposing (1) reuse/reapplication and (2) recycling/reclamation technologies and commercial approaches.

The first of these approaches focuses on the repurposing of lithium ion batteries for "second life" applications. In particular, there is a desire amongst different industries to create a supply chain for used lithium ion batteries, including establishing standard battery performance and safety metrics for the use of batteries in a chosen "second life" application. For example, used lithium ion batteries from an electric vehicle may be repurposed for use in residential and commercial solar applications.

The second of these approaches focuses on recycling lithium ion batteries by reclaiming the components and materials used to make them. In particular, these approaches focus on deconstructing the battery and using destructive technologies to reclaim the materials used to make the components of the battery. For example, rare-earth minerals and materials, like nickel and cobalt, used to make the cathode of a lithium ion battery can be reclaimed from used lithium ion batteries by using known electrochemical processes.

These approaches present potential solutions to minimize the impact from increased demand and potential shortages, but their wide-scale adoption has been slow. In order to accelerate the process, a number of governments have been actively investigating the viability of these technologies.

For example, in September 2018, the California Legislature passed Assembly Bill No. 2832 to create an advisory group to explore "second life" applications for lithium ion batteries; the advisory group is composed of members from government, private industry, and the public. Over the past 18-months, the advisory group has met quarterly to prepare recommendations regarding regulations and best practices for lithium ion battery reuse and recycling programs. The advisory group is scheduled to submit its policy recommendations to the California Legislature on 1 April 2022.

Even more recently, in June 2021, after completing its 100-day supply chain review, the Biden Administration released its electric vehicle plan. In addition to increasing the production of electric vehicles, the plan aims to fund research on the reuse and recycling of lithium ion batteries and incentivizes the recapture and recycling of materials used to make them. The United States understands that lithium ion battery reuse and recycling approaches and technologies will be necessary to minimize reliance on foreign suppliers and secure the supply chain for lithium ion batteries in the future.

Hybrid Resource Participation in Wholesale Markets

Hybrid resources typically comprise a conventional generation resource (e.g., a gas-fired plant) and an electric storage resource. Improvements to battery technology have contributed to the growing prevalence of hybrid resources in wholesale markets, leaving grid operators struggling to adapt market designs and tariff rules that were originally created for more conventional resources. The issuance of Order No. 841 established the framework for participation of storage resources in wholesale markets, but did not provide comprehensive guidance on the treatment of hybrid resources combining storage with other generation resources. Accordingly, FERC has initiated a number of proceedings to address the appropriate treatment of hybrid resources in wholesale markets following Order No. 841.

Technical Conference

In response to industry requests, FERC held a technical conference on 23 July 2020 to further explore hybrid resource participation in wholesale markets. The technical conference included panels focused on the increasing interest in hybrid resources; the interconnection challenges faced by hybrid resources; issues related to the modeling, configuration, and operation of hybrid resources; and calculation of the capacity value of hybrid resources. FERC subsequently invited post-technical conference comments, which were submitted by the RTOs/ISOs and industry stakeholders.

Hybrid Resources White Paper

On 26 May 2021, FERC Staff issued a Hybrid Resources White Paper, which addressed the topics raised by FERC Staff and participants in the July 2020 Hybrid Resources Technical Conference. The White Paper provides FERC Staff's preliminary views and observations in a handful of areas related to hybrid resources, including interconnection issues and wholesale market participation models. Simultaneously with the issuance of the White Paper, FERC also issued a notice inviting interested parties to submit comments by 18 August 2021. As a general matter, the White Paper notes that hybrid resources have the potential to provide benefits to wholesale markets, including increasing the capacity factor of intermittent or variable resources while reducing transmission congestion, as well as the curtailment of variable generation during periods of peak production. However, changes to RTO/ISO rules may be required in order to realize the full potential of hybrid resources.

The White Paper identifies four barriers affecting the integration of hybrid resources that can be addressed in tariff revisions or updates to business practice manuals. Those barriers include: (1) a lack of standard terminology; (2) a lack of uniformity in interconnection rules; (3) eligibility to participate in energy, capacity, and ancillary service markets; and (4) capacity valuation.

Participants at FERC's 2020 Hybrid Resources Technical Conference agreed that the lack of clarity and consistency in interconnection procedures across wholesale markets creates significant challenges for hybrid resources. While RTOs /ISOs permit, or are developing rules to permit, multiple resources to share a single point of interconnection and be studied under one interconnection request, FERC Staff notes that there are significant regional differences in implementation. The White Paper finds that the approach currently used by transmission providers for interconnection studies, which uses worst case assumptions, may result in exorbitant upgrade costs that do not accurately reflect the costs or capability of the resource.

The White Paper additionally finds that limits on the participation of hybrid resources in RTO/ISO capacity markets may result in an undervaluation of the full breadth of services that such resources can provide. Current participation rules do not necessarily allow for hybrid resources to provide energy, capacity, and ancillary services, thereby limiting the ability of hybrid resources to provide their full value to both project owners and the wholesale markets.

Order Directing Reports

FERC issued an order during its January 2021 open meeting directing the ISOs and RTOs to submit informational reports regarding hybrid resources. Specifically, FERC requested information on four key issues related to hybrid resources: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation. On each of these four topics, the Commission directed the RTOs/ISOs to provide a description of current practices, an update on the status of any ongoing efforts to develop reforms, and responses to the specific requests for information contained in the 19 January Order. Each FERC-jurisdictional RTO/ISO filed its report on 19 July 2021.

- **CAISO** noted that as of 1 July 2021, it had one hybrid resource participating in its market, with 12 additional co-located resources comprised of combined solar and storage. CAISO's tariff contains definitions for both hybrid resources and co-located resources, with co-located resources operating in the markets as separate and independent resources even if they are located at the same generating facility from an interconnection perspective. In contrast, hybrid resources combine different components at a generating unit location and are modeled as a single resource. CAISO has approximately 284 projects in its interconnection queue that are either hybrid or co-located, and expects significant deployment of hybrid and co-located resources in its region over the next several years.

- **ISO-NE** does not have a definition of hybrid resources in its tariff or manuals, but the market operator does permit co-located facilities to participate as either separate resources or a single resource. ISO-NE does not currently have capacity market rules specific to co-located resources, however, those resources may participate in the forward capacity auction pursuant to the rules applicable to all other customers.

- **MISO** is working on overall market-wide reforms, referred to as the Reliability Imperative, that are targeted to support the reliability, efficiency, and resilience of MISO's grid of the future. MISO's interconnection process currently permits customers to designate proposed generation facilities as hybrid resources. However, MISO noted that it does not have any operational experience with hybrid resources to date. As a result, some of the most significant challenges posed by hybrid resources include the lack of defined market participation models and operational data. MISO urged the Commission to allow RTOs/ISOs the flexibility to implement rules relating to hybrid resources in a manner and on a time horizon that best reflects each region's needs, noting that each grid operator has different market structures, interconnection processes, and system characteristics.

- **NYISO** noted that it previously filed a proposed participation model for co-located storage resources that will permit an energy storage resource and a wind or solar-fueled resource to locate behind a single point of injection for the purpose of participating in NYISO's markets. NYISO has also initiated an effort to develop a participation model for hybrid storage resources, which will offer the opportunity for multiple assets behind a common point of injection to operate as a single resource.

- **SPP** told FERC that it is working with stakeholders to develop governing language, including a definition for hybrid resources. SPP currently allows participation by co-located generation with multiple fuel types, as well as single generation resources that regularly switch fuel types. SPP and its stakeholders are in the process of developing working concepts and terminology to capture and facilitate the roles that hybrid resources may play within SPP.

- **PJM** noted that it has very limited operating experience with integrated hybrid resources. To date, only one resource has been successfully modeled as an integrated hybrid, operating both fuel types as a single unit in PJM's market. In 2020, PJM stakeholders initiated a stakeholder process to establish a clear framework for operating mixed technology resources, which is still on-going.

Comments responding to the RTO/ISO reports are due on August 18, 2021. Given the high levels of interest and complexity at issue with hybrid resources, the Commission could later determine that a formal rulemaking is needed to institute further market reforms, as it has done in recent years to remove market participation barriers for electric storage resources (Order No. 841) and distributed energy resource aggregators (Order No. 2222).

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.

Newly integrated renewable generation and energy storage projects are coming online rapidly, some with pricing that as recently as 2016. In June 2017, TEPCO 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 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 power purchase agreements (solar-plus-storage PPA) 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 one GWh of storage in the state. The estimated costs will range from eight to 10 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. 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% 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.

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 corporations 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, one 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% in 2035. The UK government is targeting the achievement of 50% 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% 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.[7] During electrolysis, electricity splits water molecules into hydrogen and oxygen within a device called an electrolyzer.[8]

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.[9] 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

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[7] 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 Util. Dist. No. 1 of Douglas Cty., *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).

[8] Dep't of Energy, *Hydrogen Production: Electrolysis*, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis (last visited Sept. 9, 2021).

[9] KEN DRAGOON, POWER TO GAS: OPPORTUNITIES FOR GREENING THE NATURAL GAS SYSTEM 19–21 (2018), http://www.flinkenergy.com/resources/Power%20to%20Gas.pdf.

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.[10]

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.[11] 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.[12] 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.[13]

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[10] Rob Van Gervwen, et al., The Promise of Seasonal Storage 27 (2020).

[11] *Id*.

[12] Dragoon, supra note 3, at 27–28.

[13] Umar Ali, *How salt caverns could transform renewable energy storage for the US*, POWER TECH. (Feb. 6, 2020), 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.

GLOSSARY

ACC	Arizona Corporation Commission
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
CRIS	Capacity Resource Interconnection Services
CSA	Capacity Services Agreement
CSRs	co-located storage resources
CT DEEP	Connecticut Department of Energy and Environmental Protection
CT PURA	Connecticut Public Utilities Regulatory Authority
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
ERIS	Energy Resource Interconnection Services
ESDER	energy storage and distributed energy resources
ESGC	Energy Storage Grand Challenge
ESI	Energy Storage Initiative
ESRs	energy storage resources
EVs	electric or plug-in hybrid vehicles
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
GSL	Grid Storage Launchpad
GW	gigawatt
GWh	gigawatt hour
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric
HNEI	Hawaii Natural Energy Institute
HPUC	Hawaii Public Utilities Commission
IP	Intellectual Property
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
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LLC	limited liability corporation
LPO	Loan Programs Office
MACRS	modified accelerated cost recovery system
MassCEC	Massachusetts Clean Energy Center
MESA	Modular Energy Storage Architecture
MISO	Midcontinent Independent System Operator
MW	megawatt
MWac	megawatts of AC power
MWh	megawatt hour
NERC	North American Electric Reliability Corporation
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.
PNNL	Pacific Northwest National Laboratory
PPA	power purchase agreement
PSE	Puget Sound Energy
PSEG	Public Service Electric and Gas Company
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
QF	qualifying small power production facility
QOF	qualified opportunity fund
QOZB	qualified opportunity zone business
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
SATA	Storage as a Transmission Asset
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
ViZn	ViZn Energy Systems
WADOC	Washington State Department of Commerce

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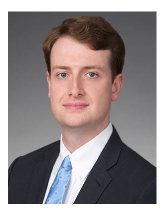

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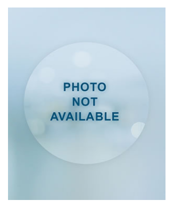

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