ORRICK
ENERGY STORAGE UPDATE
2021–2022

Including Special Updates on Solar + Storage and Hydrogen Storage

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Contents

INTRODUCTION

By any measure, 2020 served as a banner year for the global energy storage market, despite significant challenges posed by the COVID-19 pandemic. Investment in storage projects worldwide in 2020 increased almost 40% year-over-year to $5.5b, which included more than $1.5b in the United States. Moreover, 3.5 GWh of new storage capacity were installed in the United States in 2020, more than the 3.1 GWh of storage capacity installed between 2013 and 2019 combined.

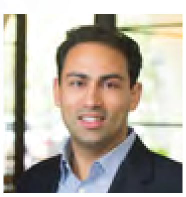
The future for storage promises even greater growth. Global energy storage capacity is expected to increase at a compound annual growth rate of 31% through 2030, reaching 741 GWh of total capacity by 2030. Over 10 GW of storage capacity is expected to be added worldwide in 2021, and the United States will account for half of those additions. By 2026, the United States is expected to add 33 GWh annually, representing an $8.5 billion domestic annual energy storage market.

Driven by this growth, battery storage projects have increased in number and size in recent years, transactions and deal structures for the development and financing of storage have proliferated, and the geographic diversity of storage projects has expanded both inside and outside the United States. In the face of the devastating impacts of climate change, governments and investors outside the United States have increased their political and financial commitments to both renewables and battery storage. Within the United States, the energy transition is well underway and storage development is at its present-day peak due to a combination of long-term decreases in battery costs, increasing renewables penetration and political momentum at the federal and state levels. These dynamics have prompted increased public and private investments into storage as well as substantial mandates for utility and other LSE procurements for products and services from stand-alone storage and hybrid/co-located storage facilities.

With the booming energy storage sector as a backdrop, we focus our attention in this fourth Orrick Energy Storage Update on the key topics and trends most relevant in today's global and domestic storage markets, including:

- **Solar + Storage:** Recent developments in offtake, EPC/procurement, financing, M&A, tax and regulatory issues in solar + storage projects
- **Trade and Compliance:** Discussion of the important trade and compliance issues impacting storage projects, including tariffs, CFIUS and bulk-power systems
- **ESG:** Highlights of Environmental, Social and Governance issues relating to storage projects, including forced labor, conflict minerals and child labor issues
- **U.S. Regional Updates:** Updates on the most active domestic regions, including California/CAISO, Texas/ERCOT, PJM and New York/NYISO
- **International Storage Trends:** Focus on recent storage trends in the United Kingdom, Japan, Italy and Spain
- **Hydrogen:** Summary of key transaction structures and issues in the burgeoning green hydrogen market

We hope this update proves useful to our clients and friends in the renewables and energy storage industries and look forward to a continued dialogue.



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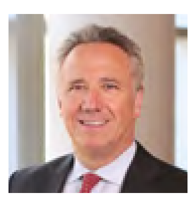

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OFFTAKE TRANSACTIONS, STRUCTURES AND ISSUES

Since our latest Energy Storage Update published in 2018, offtakers across the country, including investor-owned and municipal utilities, community choice aggregators ("CCAs"), electrical cooperatives and corporates have contracted for products and services from gigawatts of stand-alone energy storage and hybrid generation + storage projects. Although preferred use cases and value streams vary among offtakers and continue to diversify, the transaction structures we outlined in detail in 2018 — the energy storage tolling agreement, capacity sales agreement and hybrid PPA — continue to serve as the prevalent vehicles for contracting front-of-meter energy storage projects.

Focus on New Structures and Solar + Storage

In this article, we will introduce:

- the fourth and newest agreement in the market for front-of-meter stand-alone storage projects: the shared savings contract;
- several important commercial and structural issues that arise in the negotiation of solar + storage PPAs, the most popular type of Hybrid PPA today; and
- innovative structured and merchant/hedged offtake arrangements currently in the market for energy storage projects.

Shared Savings Contracts

The energy storage tolling agreement continues to serve as the most common contracted revenue structure for front-of-meter, stand-alone storage assets in the United States today. Capacity sales agreements are less common and exist primarily in regions with an active "bilateral" capacity market such as California (see our California section for important updates on Resource Adequacy and storage).

In recent years, developers of projects in the Northeastern United States and certain other jurisdictions have also entered into "shared savings" contracts to monetize unique revenue streams from stand-alone storage projects.

The shared savings contract is a variant of the energy storage tolling agreement and is used in certain ISO/RTO markets where utilities face periods of congestion and high transmission, distribution and/or capacity charges. In a shared savings contract, the project developer, as "seller," owns and operates the project for the duration of the delivery term. However, in contrast to a tolling structure, the offtaker typically does not maintain dispatch authority over the project, schedule the battery into the relevant ISO/RTO market or pay a fixed capacity charge to the seller. Instead, the seller retains dispatch and scheduling authority for the project and is responsible for charging the battery during off-peak periods and discharging it during high-demand periods to reduce annual or seasonal coincident peaks on the utility offtaker's system, resulting in cost savings to the utility offtaker. The seller is paid in connection with each peak that is successfully reduced.

Even though the seller is entitled to dispatch the project and retain other revenue streams (*e.g.*, by engaging in energy arbitrage activities or selling ancillary services into the market) when it is not being used to reduce peak load, the contracted revenue stream with the utility offtaker is inherently uncertain. It depends on the occurrence of peak demand periods and the battery's ability to perform sufficiently to achieve the agreed peak shaving requirements. Since the shared savings contract is relatively new and uncommon for front-of-meter storage projects, at this time there are no "standard" or "customary" formulas in the market for calculating the seller's compensation. This results in highly negotiated and customized compensation metrics and baselines against which savings or other benefits are measured.

Solar + Storage PPAs

When we first wrote about Hybrid PPAs in 2018, the solar + storage market was incipient, and only a handful of such agreements had been executed in the United States. Since that time, Hybrid PPAs for gigawatts of projects, primarily solar + battery storage projects, have been executed across the country, with significant activity centered in the western United States across utility and CCA offtakers. Solar + storage PPAs are now the most popular form of solar PPA actively negotiated in the United States. We expect the number of "solar-only" PPAs to steadily decrease over the coming years as energy storage continues to proliferate. In this article, we will discuss many of the important commercial and structural issues that arise in the negotiation and drafting of solar + storage PPAs, including compensation and dispatch arrangements, physical and metering configuration, grid charging and related grid interface issues, and performance guarantees.

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Compensation and Dispatch

Like standard "solar-only" PPAs, solar + storage PPAs typically require the project developer, as "seller", to own and operate the project throughout the delivery term. Under many solar + storage PPAs, the offtaker maintains dispatch authority over the solar + storage project, including the discretion to charge from the solar facility (and potentially from the grid – see below for additional detail). The offtaker will typically pay the seller (i) a capacity charge (a fixed $/kw-month of tested battery capacity – usually determined by a COD test and annual tests during the delivery term) and (ii) an energy charge (an as-available $/MWh of solar output). In contrast, some offtakers will instead pay only an oversized capacity charge, and still in other cases, offtakers will pay only an oversized energy charge. In some transactions where only an energy charge is paid, offtakers do not seek dispatch authority, leaving such authority with the seller and instead providing other incentives and imposing other obligations on the project. For example, certain offtakers agree to pay a disruptively high premium "adder" to the as-available $/MWh price of energy delivered during evening peak periods, and the premium amount may vary depending on the hour and season of dispatch.

Physical and Metering Configuration

The physical and metering arrangements for any solar + storage project raise important issues for the parties' rights and obligations under the Hybrid PPA. For instance, whether the storage facility is AC-coupled or DC-coupled with the solar modules will impact not only the operating and efficiency parameters of the project but also the PPA provisions relating to charging/discharging, dispatch rights, compensation and operating parameters.

In addition, the number and location of revenue meters used for a solar + storage project will directly impact compensation terms, delivery terms and efficiency guarantees for the project. Solar charging energy will be lost to some extent due to efficiency losses and line losses resulting from the battery. The location of revenue meters measuring each flow of energy (including solar output, whether or not used to charge the battery, charging energy from the grid and discharged energy from the battery) will therefore impact the seller's compensation and may, depending on the state and ISO/RTO involved, impact the number of renewable energy credits ("RECs") generated by the project. Round-trip efficiency calculations rely on the measurement of charging and discharging energy and thus are directly impacted by the location of meters. In CAISO, solar + storage projects may be classified as either "co-located" or "hybrid" projects, which raise other unique metering and settlement issues, addressed in further detail in the California section below.

Grid Charging and Grid Interface

Where a solar + storage project is grid-tied and within an ISO/RTO system, the offtaker will often desire the ability to charge the storage facility with grid energy in order to utilize the battery during periods of low solar irradiance. In addition to the basic interconnection and operating considerations that are implicated by grid charging, one principal issue almost always evaluated is the applicability of the investment tax credit ("ITC") to the storage facility. As described in detail in the Tax section below, the seller's ability to claim and monetize the ITC is determined by the ITC "cliff test" and various other requirements.

Some developers, anticipating conservative tax equity investors, disallow any grid charging whatsoever under the solar + storage PPA until the expiration of the ITC recapture period and may or may not expressly address the offtaker's right to grid charge thereafter. Where offtakers insist on grid charging flexibility during the ITC recapture period, certain developers will provide such flexibility but in such cases will usually limit it to substantially lower than 25% grid charging on an annual basis in order to avoid any risk that the 25% "cliff" will ultimately be exceeded by the end of any calendar year. Occasionally, offtakers will desire the unrestricted ability to charge from the grid during the ITC recapture period and may offer to indemnify the seller for lost ITC value. However, the process of accurately and prospectively calculating and valuing forgone ITC benefits is opaque and challenging and may not be favored by some tax equity investors.

Introducing grid charging raises several other issues unrelated to the ITC in a solar + storage PPA. First, the metering and compensation arrangements will need to account for at least some portion of metered energy as originating from the grid, not the solar facility. Second, solar + storage PPAs will often ensure that the offtaker's grid charging rights and the project's interconnection capacity limitations will not result in an uncompensated curtailment of solar production. For instance, the PPA provisions either (i) limit the offtaker's ability to grid charge or discharge the battery if doing so would result in a curtailment of the solar facility or (ii) permit such offtaker to do so if the seller is compensated for any curtailed solar production.

Performance Guarantees

Many solar + storage PPAs require the seller to achieve agreed levels of capacity, availability and efficiency upon commercial operation of the project, and to continue achieving the same or similar performance targets throughout the delivery term. Some solar + storage PPAs also require the project to achieve other guarantees, such as minimum charging and discharging times, maximum charging and discharging rates, self-discharge rates, ramp rates, response times and others, at and/or following commercial operation. The failure to achieve one or more of the guarantees during the delivery term will typically result in either reductions to the seller's regular capacity payment or damages assessed against the seller. Often, severe or chronic availability shortfalls (and, sometimes, severe or chronic capacity or efficiency shortfalls) trigger events of default and offtaker termination rights. The storage market is still in the process of settling on standards, thresholds and ranges for the more common guarantees and offtakers may place different priorities on certain guarantees based on their intended use cases for the solar + storage project.

Each of the three primary performance guarantees – capacity, availability and efficiency – generates unique issues in a solar + storage PPA. A fixed capacity guarantee for the delivery term is common in many solar + storage PPAs and requires ongoing augmentation during the delivery term. However, some offtakers agree to a long-term degradation schedule. Capacity guarantees are typically monitored through regular (often annual) capacity testing of the storage facility. Because capacity payments in a solar + storage PPA are usually calculated based on the level of tested capacity, the capacity payment is automatically reduced if the tested capacity of the storage facility falls below the guaranteed value.

Certain solar + storage PPAs in the California market either tie capacity payments to the quantity of capacity attributes (Resource Adequacy) delivered to the offtaker or assess damages against the seller for shortfalls in Resource Adequacy, thereby potentially exposing the seller to change in law/tariff risk. The seller's exposure to this type of change in law/tariff risk has been especially pronounced in recent years in California, and is often addressed through a compliance cost cap or other agreed cap on seller liability. (See our California section for a more detailed discussion on these matters). In any case, the primary approach to curing a capacity shortfall is to correct or augment the battery capacity of the project, so solar + storage PPAs will often provide the seller with cure rights and cure periods to address any capacity shortfalls in advance of triggering an event of default under the PPA.

Although the scope and requirements for availability guarantees vary among solar + storage PPAs, in most cases the seller is required to ensure that the actual storage capacity of the project is mechanically available to receive and respond to dispatch instruction. Availability guarantees are usually calculated on an average basis over a fixed period of time, and failures by the seller typically result in monetary penalities through either a reduced capacity payment or the imposition of damages. In addition to the basic availability guarantee level, two other issues are commonly negotiated in the context of availability guarantees. First, the parties must agree on how "availability" is defined and measured. Some solar + storage PPAs measure it based on the proportion of available capacity over a period of time, which may be a month or a year or even certain seasons or peak periods. Second, the parties must agree on the excuses provided to the availability guarantee. Most solar + storage PPAs will excuse *force majeure*, curtailment and buyer breach from the availability guaranty, and some will also excuse certain outages, major equipment failures and even serial defects.

Efficiency guarantees are common in solar + storage PPAs, and they raise several important and highly negotiated issues. For instance, the measurement location of round-trip efficiency (*e.g.*, the point of interconnection or the storage project itself) is a basic but important factor in measuring round-trip efficiency and determining whether the guarantee is satisfied. In addition, some offtakers will seek to prohibit any use of solar output, charging energy and/or discharging energy to satisfy the battery's station load, which can both impact project economics and implicate the project's efficiency guarantee. Finally, the specific penalties and remedies associated with a failed efficiency guarantee are of particular importance, including the formula for determining damages and the Seller's cure rights and cure periods (including for any event of default triggered by a failed efficiency guarantee).

New Structures and Strategies

Novel structured products and hedges for both stand-alone storage projects and solar + storage projects are growing rapidly across various United States jurisdictions. Several developers have now structured, or are actively negotiating, arrangements under which an individual storage project (stand-alone or solar + storage project) has multiple offtake arrangements. For instance, some stand-alone projects receive one or more capacity payments for Resource Adequacy (in California), transmission deferral payments or capacity payments as a non-wires alternative resource, while retaining the ability to sell energy and ancillary services into the applicable ISO.

Solar + storage projects are also being used to provide firm product to some offtakers. For example, certain offtakers are procuring solar + storage PPAs in which the Seller retains dispatch authority over the battery and guarantees the offtaker a shaped production curve (on a 7x16 or other shaped basis) and associate RECs, and capacity attributes may be sold to the same or different offtaker. In these transactions, subject to the fixed shape requirements, the Seller is otherwise entitled to sell products into the ISO and retain resulting revenue streams.

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Stand-alone storage projects have also recently been the subject of various hedge arrangements, particularly in the California and ERCOT markets. Some stand-alone storage projects have been hedged using the "TB4" or "top bottom 4" structure, in which the developer is paid the difference between the top 4 hours' system price minus the bottom 4 hours' system price in a single day. The seller in these circumstances has the flexibility to otherwise utilize and dispatch the project as it wishes, and essentially hedges its arbitrage strategy. In the ERCOT market, and as discussed further in our Texas section below, portfolios of stand-alone battery projects have been the subject of short-term hedges for ancillary services prices.

EPC STRUCTURES, TESTS AND GUARANTEES

EPC Structures

Engineering, procurement and construction arrangements for battery storage systems have developed substantially over recent years, as developers and financing parties have become increasingly comfortable with various elements of technology and contracting risk associated with battery storage projects. In the early days of battery storage project development, the more common method of procuring a battery storage system was through a fully wrapped EPC contract under which a single contractor would be responsible for the procurement, installation, testing and long-term performance of the battery storage system. Since then, many developers have begun directly procuring significant and distinct portions of the battery storage systems and civil works activities under separate contracts to reduce capital expenditures.

In recent years, a spectrum of procurement structures has emerged governing procurement of battery storage systems. On one end of this spectrum is the fully wrapped EPC approach described above, under which the project owner allocates substantially all of the procurement and performance risk to one single creditworthy contractor and pays the contractor a "wrap" premium to bear this risk. On the other end of the spectrum, a project owner will enter into a limited "integration" contract, under which the integrator will perform limited services, such as construction management and/or procurement management services, and may also provide software solutions for the dispatch of the battery storage system (described in more detail below). On this other end of the spectrum, the project owner acts as a "general contractor" and self-procures most or all of the equipment of the storage system through multiple direct procurement arrangements across a variety of vendors, likely saving on the "wrap premium" but taking on more construction and completion risk.

> Many developers are building battery storage projects in the middle of this spectrum – by contracting for the procurement, installation, commissioning and long-term maintenance and performance guarantees for a battery storage system through multiple contracts.

Most recently, however, many developers have been building battery storage projects in the middle of this spectrum – by contracting for the procurement, installation, commissioning and long-term maintenance and performance guarantees for a battery storage system through multiple contracts: most commonly a procurement, commissioning and testing contract with the battery supplier and a separate installation or "balance of plant" contract with an EPC contractor. Wind projects are a model for such contractual arrangements. It has been common for decades for a turbine supplier to deliver equipment for an EPC contractor to install, after which the supplier returns to the site to confirm proper installation and then commission the wind turbines.

For a battery integrated with a solar or other energy generation system, the solar system is often supplied and installed by yet another vendor or contractor. For these projects it is paramount to establish a detailed division of responsibilities among the various contractors so each party knows where its responsibility begins and ends. This is challenged by the fact that different battery manufacturers require a different installation scope, so the detailed division of responsibility may not be known at the time the project developer is soliciting bids for the various scopes of work. In our experience, a common issue that extends and complicates negotiation of these contracts is resolving misunderstandings of scope split between the contractors and sequencing the delivery, installation and commissioning of the battery system with the optimal incentives to keep the project on schedule and avoid change orders from one contractor due to another contractor's delay.

Another critical component is ensuring that performance and economic exposure of the developer under its offtake agreement (*e.g.*, for a solar + storage project described in the previous section) is allocated appropriately to the vendor(s) and contractor(s) most able to backstop the risk from a credit and capability standpoint. This includes risks under the offtake agreement associated with schedule (usually addressed through delay performace liquidated damages), performance (usually addressed through various performance guarantees and associated liquidated damages) and default (under which the developer will often owe a capped or uncapped termination payment to the offtaker). Although it is not common for the developer to be able to pass on all of its schedule and performance risk under the offtake agreement to vendors and contractors involved, it is possible to "flow-down" substantial offtake obligations to the vendor through provisions and guarantees in the supply and construction contracts and to negotiate damage amounts that backstop as much as possible the damages owed under the offtake agreement.

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Performance Tests and Guarantees

A critical component for any project development and financing for an energy project involving a battery storage system is properly structured contracts for the performance tests at commissioning of the system and long-term performance guarantees. For battery systems, to date, the vast majority of projects procure these obligations from the battery equipment provider. As described above, there is more variety in the approach to installing the battery system and balance of plant work and integrating it into a hybrid energy system. For purposes of this section, we will refer to the party conducting the work on the project as the "contractor," understanding that, depending on context, this may be the battery equipment supplier or the EPC or installation contractor. The EPC and installation provisions and long-term performance guarantees must be provided by a creditworthy entity or backed by credit support, or both.

Below is a brief description of the key battery acceptance tests and long-term performance guarantees relevant to battery systems that can be expected to be included in large-scale battery system procurement contracts (including hybrid generation plus storage projects, like solar + storage projects) as well as other considerations for the key contracts. Market and industry standards are evolving for each of these guarantees and tests and for the contractual remedies attached to shortfalls in each. The relative importance of various tests and remedies still varies among projects, depending on the offtake structure and/or projected market participation.

1. Capacity. Capacity guarantees and tests will typically be required not only as a condition to acceptance of a project at substaintial completion (or similar milestone), but also as a continuing guarantee through some form of continuing multiple-year performance guarantee or via a long-term service agreement ("LTSA"), capacity maintenance guarantee or other contractual structure. In order to confirm the capacity (in MWs) of a battery storage system or the power and energy that can be discharged by a battery project (in MWhs), the contractor will almost always be required to conduct a capacity test. One common test is to discharge the battery system from its maximum to minimum states of charge at the maximum discharge rate for the project. The amount of MWhs of metered energy discharged may then be divided by the duration of the discharge to determine the project capacity (in MWs). The actual capacity as so determined would then be used to evaluate battery supply contract compliance. If compliance is not satisfied, the contractor is typically permitted a period of remedying and re-tests until either the capacity test is satisfied (a "must-make" capacity guaranty) or the contractor is permitted to "buy down" the capacity to a limited degree (usually 1-5% of total capacity) by paying liquidated damages. If the contractor buys down the capacity, the reduced capacity becomes the new baseline for the system's defects warranty or, if applicable, the ongoing performance guarantees under the LTSA. Whether a project requires a "must make" capacity test or allows a buy-down depends on the COD requirements of the offtake contract, some of which require the system to achieve 100% of expected capacity (in which case the contractor is likely to overbuild the project's capacity to ensure compliance). Passing the capacity test and paying any buy-down liquidated damages will be a condition to the key payment and schedule milestone that often has its own delay liquidated damages (typically a "commissioning," "acceptance," "substantial completion" or other similar milestone). In the buy-down scenario, the contractor is sometimes faced with the decision of whether it is better to pay the buy-down price so it can achieve the milestone and stop the delay liquidated damages from accruing, or continue to try to remedy the shortfall, incurring the cost of the remedy and the daily LDs while the remedy is implemented, including the time it must wait for replacement or supplemental equipment to get to the project site.

2. Charge and Discharge Rates. A contractor will frequently be required to conduct a charge rate or charge time test in order to confirm the time required to charge the system from its minimum to maximum states of charge. Although testing details may vary, the contractor may be required to calculate the average charge rate based on the amount of energy charged and the amount of time taken to achieve the maximum state of charge. Similarly, the contractor may be required to conduct a discharge rate test, which is essentially the reverse.

3. Availability Testing. In order to ensure that a battery system is suitable for commercial operation, a contractor will typically be required to satisfy an availability test over some agreed period of hours or days to ensure that the system operates as expected for the duration of such test. Although details of these tests vary widely, one general approach involves allowing the owner to control and direct operation of the system for a specific time period. The owner selects the set points for the system's operation in a manner consistent with the guaranteed technical specifications and the pre-established charge rate and system capacity and then determines for each relevant settlement interval (*e.g.*, a 5-minute interval) whether the system has operated at its guaranteed or expected level. A calculation is then performed to determine the system availability based on the percentage of settlement intervals during which the system operated at, or within some agreed band or level of deviation from, the expected level. Availability guarantee concepts are also a critical component to any LTSA contract. Particularly with LTSAs, "availability" may actually be a combination of system uptime and capacity. For example, if the system is operating below expected capacity (based on a periodic capacity test), the availability for that interval will be the percentage of capacity available. If the system is not available at all, the availability will be 0% (regardless of the most recent capacity test). These inputs are then blended into a single availability/capacity figure upon which remedies are determined.

4. Round-Trip Efficiency Testing. A battery system will typically be tested for its round-trip efficiency, meaning the percentage of the energy that has been delivered or charged into the system that can be discharged. Although efficiency test details vary, one simple approach is to measure the amount of energy charged into a system required to take the system from its minimum to maximum states of charge and then measure it against the amount of energy discharged through the system's meter to take the system back to its minimum state of charge. By comparing the quantity of energy stored by a battery system at the beginning of an efficiency test against the total quantity discharged by the system at some later time, the quantity of energy "lost" (and thus the system's efficiency) will be determined.

5. Other Tests. Several other tests are in use both at acceptance (or "substantial completion") of the system under the primary supply contract and on an ongoing basis under the LTSA. The tests depend on the importance of various aspects of performance over the life of the system, including auxiliary load testing (measuring how much load the project itself consumes outside of the losses from imperfect round-trip efficiency from systems like climate control, lighting and fire suppression), standby self-discharge (measuring the "leakage" of energy from charged cells over time), response time (measuring the time it takes the system to discharge at its full capacity after it has received a signal to do so), noise testing and various sub-system tests (HVAC, fire suppression, etc.).

6. Testing Remedies. The same principles that apply to the remedies for failing to meet the capacity tests as described above generally apply to the other tests. That is, a project owner must determine for each test whether it is a "must-make" or "must-meet" test which is required to be passed in order for the contractor to achieve the completion milestone, or instead, whether the contractor is allowed to "buy down" any performance deficiency to achieve completion with minor shortfalls by paying liquidated damages. Some tests, such as round-trip efficiency tests, are quite difficult to remedy once the system has been built so, there is typically a buy-down sized to approximate the system owner's loss of value over the life of the system due to that shortfall (though sometimes there is an option to pay an annual buy-down if the contractor believes it can improve round-trip efficiency over time). Other tests, such as capacity tests, are relatively easy to remedy (often by adding more battery cells) and therefore lend themselves to a must-make test (or two levels of performance – a must-make level and a higher buy-down level). As described above, if there is a buy-down, the bought-down performance level will typically form the baseline for ongoing defects warranties and performance guarantees.

7. Control Systems and System Data. The control system for a battery storage system will be an important point for both diligence and decision-making early in the process of developing a project, particularly a battery that will be integrated with a solar or other energy facility. Battery systems have a battery management system ("BMS") that controls the individual cells and collects data on their operation, as well as an energy management system ("EMS") that controls the charge and discharge of the entire system and collects data on system operation. The more sophisticated systems, particularly for hybrid projects, will assist with making operational decisions, weighing when it is financially advantageous to charge or discharge the battery based on a range of factors, predicting the optimum charge level of the battery at a given time, managing the battery for longevity and minimizing capacity or other performance degradation and a number of other factors. Since this last piece of hardware and software often will need to be programmed to work with a particular project's makeup, financial model and offtake contract, the battery system supplier is not always the right fit, and developers often turn to independent engineers and other vendors to develop these systems. Project owners must have a clear understanding of the level of access, ownership and license they are granted with respect to the data generated by the battery system. Some battery system suppliers may limit data access in ways that are not compatible with the owner's need for system monitoring and testing (particularly compliance with performance guarantees and offtake reporting requirements), their desire to more fully understand system operations across a fleet of projects or to eventually hire a third-party maintenance provider or to self-perform maintenance.

STORAGE FINANCING AND M&A

Financing markets are active for both solar + storage and stand-alone storage projects, with the greatest activity in solar + storage projects driven by the federal ITC availability for tax equity investors. The industry is awaiting the Biden administration's infrastructure package as each of the proposals for an ITC for stand-alone storage or cash grant or direct-pay options, could have a significant impact on the financing markets.

Although financing parties generally tend to evaluate storage projects similarly to other renewables projects, we have seen certain exceptions. They relate primarily to the dependability of the underlying revenue streams, storage technology and degradation, and the various project counterparties involved. Unique strategies to address these issues include:

Contracted vs uncontracted revenue streams. While the preference remains for contracted revenue streams (with capacity and availability contracts being the simplest from a lender's perspective), there is some appetite in the financing markets for financing merchant revenues that constitute some percentage of overall revenues, such as when a project with a long-term resource adequacy contract sells energy and ancillary services on the spot market.

***Note:** Texas Winter Storm Uri and its impacts on the ERCOT market have introduced greater degrees of complexity and scrutiny in financing projects that involve a larger merchant component with respect to the battery, multiple revenue streams or hedges. However, the inclusion of a storage component to projects may be an important factor to lenders in assuring that debt financing will be serviceable following extreme weather events.*

Technology risks. Factors such as battery degradation and useful life require financing parties to conduct additional diligence and engage with independent engineers on such items. Technology supplier performance guarantees, capacity maintenance agreements and the creditworthiness of such suppliers are also areas of focus. We have seen some financing parties require capital expenditure reserves for replacement of batteries over time. Another option is to obtain insurance for perceived insufficiencies in modeled capacity, energy or power, availability or round-trip efficiency assumptions.

***Note:** The bankability and available financing for nascent technologies is still relatively scarce as investors, at scale, need a track record of success. But the adoption of proven technologies such as lithium-ion has resulted in collapsing prices for the most common storage technologies.*

Other transferability concerns related to limitations in storage system expertise. Developers should pay special attention to "qualified transferee" provisions in financing and project documents to ensure they are not overly restricted to providers with *e.g.*, multiple years' experience with a specific technology.

***Note:** Following the Texas Winter Storm, we have seen tax equity investors reevaluate both the net worth and experience standard for "qualified transferees." For example, we have seen the range of acceptable net worth increase from between \$500m and \$750m to between \$750m and \$1b. We have also seen some tax equity investors reject satisfaction of an experience standard through contracting with an experienced operator or manager. In addition, some tax equity investors are requiring sponsors to make additional capital contributions in the event of market disruptions.*

Grid charging. Allowing any portion of the project to be charged from the grid is a key issue impacting tax credit qualifications in the tax equity market. Most investors do not allow any grid charging during the recapture period, although there are a few exceptions, such as in the portfolio context and when no tax credits are being claimed for the maximum portion allowable for grid charging. Managing members of a tax equity partnership should ensure that tax equity grid charging restrictions are passed through to the O&M and asset management providers. An issue can also arise if grid charging (or other non-solar charging, such as from a diesel generator) is required during the testing period for the battery. If mechanical completion has occurred and the battery might have been placed in service for tax purposes, this grid charging might reduce the tax credits available for the battery.

O&M and asset management. Concerns have arisen over the ability to replace service providers due to the limited (although growing) expertise in this area as well as the proprietary nature of the energy management system ("EMS") software used by many service providers. Financing parties may address these concerns by requiring "lockbox" protections for the intellectual property contained in such software, whereby the source code is placed in escrow and may be released upon certain trigger events, such as bankruptcy of the provider.

M&A. Previously, when the ITC for stand-alone storage did not seem like a realistic possibility, buyers were willing to give sellers the full benefit of such an ITC coming to fruition. However, as it looks more and more likely that the Biden administration will enact an ITC for stand-alone storage buyers are negotiating for some or all of the benefit of such an ITC.

As the storage market matures, the M&A market for both stand-alone storage and solar + storage is fairly robust, with lots of competition both for development stage and operating stage projects. In addition, there are a fair amount of joint venture investments focused on storage, assets (often in combination with other solar assets).

M&A considerations for stand-alone storage and/or solar + storage transactions generally follow the same trends as for solar M&A transactions, with a couple of key exceptions. While solar transactions have recognized sources for the merchant curve, in storage transactions buyers are more likely to use a proprietary merchant curve model and are often unwilling to share such curve.

TAX ISSUES

The main federal tax incentive for battery energy storage systems ("BESS(s)") is the ability to claim the federal Investment Tax Credit ("ITC") under Section 48 of the Internal Revenue Code of 1986 (as amended, the "Code") when the BESS is charged with energy generated by, and is integrated with, one or more solar generation projects (or other renewable energy projects) that are themselves eligible for the ITC. The ITC is currently unavailable for stand-alone storage projects. However, there have been a number of recent legislative proposals to add a new category of ITC for stand-alone storage projects into the Code. If ITC became available for stand-alone storage projects, it would no longer be necessary to analyze a particular BESS to see if it meets the requirements to count as part of an ITC-eligible solar facility as described in this article. This development would potentially not only open access to tax equity investment for stand-alone storage projects, but it would also make obtaining tax equity financing for a solar + storage project much simpler.

The ITC is available for certain qualifying energy facilities, including solar energy property that uses solar energy to generate electricity. A BESS, on its own, is not qualifying energy property within the meaning of Section 48. The regulations provide that the term "solar energy property" can include storage devices. The IRS has confirmed in several private letter rulings that storage devices are eligible for the ITC. But the existing guidance leaves open several questions as to what is required for a BESS to qualify as solar energy property for ITC purposes.

Although the regulations do not explicitly require that a BESS be "a part of" or "integral to" or "functionally interdependent with" a solar facility in order to qualify as solar energy property, developers and financing parties often focus on the interdependence of the BESS with the solar facility for the purposes of determining ITC eligibility.

The specific requirements in the regulations are that the BESS not be included in (or beyond) "the stage that transmits or uses electricity" and that the 75% cliff test, described below, is met. Many tax practitioners question whether an individual BESS's particular relationship to (or interdependence with) an individual solar facility needs to be analyzed in order to determine if the BESS is ITC-eligible for the following reasons: (a) The Code does not provide for ITC for a stand-alone storage system, (b) a BESS can only derive its ITC eligibility from qualifying as "solar energy property" (or some other type of ITC-eligible property) and (c) some of the relevant guidance analyzes ITC eligibility of certain property based on its being "integral to" or "functionally interdependent" with other qualifying property. For purposes of this article, we refer to these considerations as the "Interdependence Factor." Some of the relevant questions with regard to the Interdependence Factor include whether the BESS is installed at the same time as the solar facility, whether the relevant BESS is owned by the same taxpayer as the relevant solar facility and whether the relevant BESS is physically co-located with and receives its charging energy from the relevant solar facility.

The 75% Cliff Test

The main technical rule in the regulations on ITC eligibility for storage systems is commonly called the 75% "cliff test." The regulations provide that a solar energy storage system qualifies as solar energy property "(i) only if its use of energy from sources other than solar energy does not exceed 25 percent of its total energy input in an annual measuring period and (ii) only to the extent its basis of cost is allocable to its use of solar during an annual measuring period." For this purpose, an annual measuring period is the 365-day period beginning with the day the BESS is placed in service. If less than 100% of the energy used to charge the BESS during this annual period is generated by solar sources, the ITC-eligible cost of the BESS is reduced proportionately. If the 75% cliff test is not satisfied, then no portion of the storage system's cost is eligible for the ITC.

The ITC "vests" ratably, i.e. 20% per year, over the five-year recapture period beginning on the date a BESS is placed in service. If the percentage solar charging for any annual measuring period during the five-year recapture period is lower than the percentage solar charging in any of the prior annual measuring periods, then the "unvested" portion of the ITC claimed with respect to the BESS will be recaptured at the rate of the of the decrease in solar charging (if not already recaptured in an intervening prior annual measuring period). A subsequent increase in the percentage solar charging in a later annual measuring period does not result in additional ITC or an "unwinding" of the ITC recapture. Because of this rule, if the planned use of the BESS will include some non-solar charging (*e.g.*, grid charging) financing parties focus on the maximum amount of permissible solar charging during the five-year recapture period.

The cliff test does not specify that all solar energy must come from a single solar facility. Arguably, a BESS could meet the 75% cliff test so long as at least 75% of the charging energy for each annual measurement period can be traced to one or more solar facilities (even if some of those solar facilities are located remote from the BESS or owned by other taxpayers). But such a cross-charging arrangement might be viewed as reducing the Interdependence Factor and could raise questions as to whether the BESS qualifies for the ITC.

Timing of the Installation of the BESS

The regulations are silent whether a BESS needs to be installed at the same time as the underlying solar facility in order to qualify for the ITC. In addition, two private letter rulings support the conclusion that a storage system does not need to be installed at the same time in order to qualify for the ITC. In PLR 201208035, the IRS ruled that a storage device that was added to an existing wind farm qualified for the ITC. Under a different Code section, in PLR 201809003, the IRS ruled that a battery system added to a residential solar system would qualify for the residential energy credit under Section 25D.

Ownership of the BESS

The regulations also do not address whether a BESS and the underlying solar facility need to be owned by the same taxpayer in order for the BESS to qualify for the ITC. In both of the private letter rulings involving a storage system added at a later date (discussed above), the same taxpayer owned both the storage device and the underlying qualified energy system. Therefore, the most conservative approach would be to assume that the same taxpayer must own both the BESS and the solar facility. Given that there is no explicit prohibition on separate ownership in the applicable IRS guidance, some financing parties may be comfortable with separate ownership.

Physical Location of the BESS

Under the regulations, solar energy property includes only equipment up to (but not including) the stage that transmits or uses electricity. In Chief Counsel Advice 201122018, in the context of the Treasury cash grant ("Cash Grant") program under Section 1603 of Division B of the American Recovery and Reinvestment Act of 2009, the IRS defined the boundary of a cash grant-eligible wind project as the point where voltage is stepped up for transmission. To avoid a concern around what counts as being part of the transmission stage, tax practitioners often use the main power transformer as the boundary line for what counts as ITC-eligible property in a solar facility (with any components beyond the high-voltage side of the transformer being treated as ITC-ineligible). The applicable IRS guidance does not explicitly state that a BESS cannot qualify for the ITC if it is located on the high-voltage side of the transformer or otherwise remotely located from the solar facility. Nonetheless, the most conservative approach is to assume the BESS should be physically co-located with the relevant solar facility and connected on the low voltage side of the main power transformer.

Implications for Obtaining Tax Equity Financing for a BESS System

As described above, the relevant guidance is not entirely clear on the requirements of a BESS to qualify as solar energy property for ITC purposes or the specific degree to which the BESS must have a high Interdependence Factor. The most straightforward fact pattern for a BESS to qualify for the ITC is a situation where the BESS is charged solely from a single solar facility and where the BESS and the solar facility are installed at the same time, physically co-located with the BESS installed on the low-voltage side of the main power transformer, and owned by the same taxpayer. This straightforward fact pattern creates the strongest Interdependence Factor.

> The most straightforward fact pattern for a BESS to qualify for the ITC is a situation where the BESS is charged solely from a single solar facility and where the BESS and the solar facility are installed at the same time, physically co-located with the BESS installed on the low-voltage side of the main power transformer, and owned by the same taxpayer.

Although good arguments can be made that variations on the straightforward fact pattern described above should not cause a BESS to fail to qualify for the ITC so long as the 75% cliff test is met, any such variation will likely decrease the Interdependence Factor and may cause potential financing parties to question whether the BESS will qualify. Financing parties may give preference to solar + storage projects that follow the straightforward fact pattern described above.

TRADE AND COMPLIANCE

The U.S. government's national security and related policy concerns associated with international trade and investment have intensified in recent years, especially with regard to China. For good or ill, this is an area in which there is a rare bipartisan political consensus.

International trade and investment legal restrictions emerging during this and the prior two presidential administrations are having a substantial impact on the solar power storage sector. This section explores the effects of:

- import duties purportedly intended to achieve national security and trade-fairness goals;
- deployment of import duties to address findings of human rights abuses;
- restraints on foreign investment for national security reasons; and
- an executive order established to authorize restrictions on international sourcing of equipment for bulk power production.

We also analyze how procurement and offtake contracts in the market today address these regulatory constraints.

Import Tariffs – Section 301, Section 232, Section 201 and AD/CVD Orders

Tariffs under Section 301 of the Trade Act of 1974 apply to a variety of products from China, including photovoltaic cells, modules and inverters. The tariffs under Section 301 adversely affect energy storage projects that use certain lithium-ion batteries: a 7.5% Section 301 tariff (reduced from 15% in January 2020) applies in addition to general rate of duty at 3.4% ad valorem to imports of electric storage batteries classified in subheading 8507.60.0020, Harmonized Tariff Schedule of the United States. These tariffs are potentially adjustable by the Biden administration.

Tariffs under Section 232 of the Trade Expansion Act of 1962 are currently imposed on nearly all steel and aluminum imports, impacting the solar industry by raising the cost of solar racking, wiring and ground-mount posts. Tariffs under Section 201 of the Trade Act of 1974 apply to imports of certain Crystalline Silicon Photovoltaic ("CSPV") products and are scheduled to expire on February 6, 2022. Finally, there are antidumping and countervailing duty tariffs that apply to certain CSPV products made in China. The Commerce Department generally revises antidumping and countervailing duty levels annually.

Expanded Tariffs in Connection with Human Rights Violations

China's Xinjiang Uyghur Autonomous Region ("Xinjiang") is the global production epicenter of high-quality polysilicon vital to solar power production. Human rights groups have raised concerns about forced labor associated with products produced in Xinjiang. The U.S. government has responded with a growing set of legal measures authorizing restraints on imports from Xinjiang. The response has included Withhold Release Orders ("WROs"), which make imports of subject items illegal absent overcoming a rebuttable presumption that products subject to a WRO are a result of forced labor. The U.S. government may apply one or more WROs to some of all polysilicon from Xinjiang.

Separately, the Senate is considering the Uyghur Forced Labor Prevention Act, passed by the U.S. House of Representatives in September 2020, which would establish a rebuttable presumption that all labor occurring in Xinjiang, or associated with Xinjiang's "poverty alleviation" or "mutual pairing assistance" programs, constitutes forced labor. If the bill becomes law, it would be expected to effectively ban U.S. import of polysilicon from Xinjiang.

CFIUS Treats Foreign Investment in Solar Power Production and Energy Storage as a Security Challenge and Screens Sensitive Transactions

For national security reasons, the U.S. President can block foreign investment in the United States that is subject to screening by the Committee on Foreign Investment in the United States ("CFIUS"). Until implementation of the Foreign Investment Risk Review Modernization Act ("FIRRMA") of August 2018, CFIUS had the authority to examine and disrupt transactions only if they could result in a foreign person having, directly or indirectly, control over a U.S. business. Further, the law never required parties to notify CFIUS of any given transaction. With FIRRMA, CFIUS is authorized to screen not only covered "control transactions" but also certain non-controlling investments and certain real estate transactions. And the new law requires parties to notify CFIUS of some types of covered transactions.

Circumstances in which a CFIUS filing is legally required are rare for foreign investment in power production projects. The possibility of a CFIUS filing requirement for foreign investments in energy storage projects is greater as energy storage technology can be a "critical technology." A critical technology is generally an item that commonly requires an export license to be exported. In some circumstances, CFIUS filings are mandatory for foreign investment in projects that involve production, design, testing, manufacturing, fabrication or development of a critical technology.

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In some circumstances, a CFIUS filing may not be legally required but, especially from the perspective of a foreign investor, may be prudent. These include investments in projects that involve a security-sensitive aspect, such as a critical technology or critical infrastructure. A project can involve security-sensitive critical infrastructure if it performs or will perform specified "functions" (owning, operating, manufacturing, supplying or servicing) with respect to certain sensitive systems and assets. Power projects that present security sensitivities are those with close proximity to military installations and where the buyer or key equipment is connected to China or Russia.

CFIUS ordinarily clears transactions that it screens. CFIUS may, however, condition clearance of sensitive transactions on mitigation arrangements, such as modifications of transaction structure, the parties' contractual commitments to the U.S. government or both. In the context of power production and storage projects, CFIUS's mitigation arrangements have focused on U.S. government scrutiny of sourcing of equipment that is connected to China. CFIUS's restraints can extend not just to equipment from China but also to suppliers and equipment that are related to China. CFIUS's concerns have centered on equipment the government believes can be manipulated via cyber or supervisory control and data acquisition systems to affect power production or supply levels.

Bulk-Power System Executive Order Expected to Limit Sourcing of Power System Equipment

On May 1, 2020, President Trump issued Executive Order 13920 (E.O. 13920) to address perceived national security concerns related to China and Russia and the U.S. bulk-power system ("BPS"). E.O. 13920 would authorize government review of and prohibitions on certain transactions involving BPS electric equipment "designed, developed, manufactured, or supplied, by persons owned by, controlled by, or subject to the jurisdiction or direction of a foreign adversary," that pose an "unacceptable risk" to U.S. security. E.O. 13920 was thought to be needed because CFIUS national security screening is limited to foreign investment transactions.

The Department of Energy ("DOE") was tasked with administering E.O. 13920 and issuing implementing regulations by September 28, 2020. The regulations were expected to provide sufficient guidance to make a determination as to whether specific facilities or equipment are "needed to maintain transmission system reliability" or are "necessary for operating an interconnected electric energy transmission system." But before DOE provided guidance on applicable components of the BPS that would be subject to the order, effective January 20, 2021, President Biden suspended E.O. 13920.

Three months after President Biden suspended E.O. 13920, DOE announced a new request for information ("RFI") on April 20, 2021 indicating that the U.S. government is considering whether to recommend a replacement order. The RFI seeks information from electric utilities, academia, research laboratories, government agencies and other stakeholders on various aspects of the electric infrastructure. In the RFI, DOE asks for input on specific questions related to development of a long-term strategy to protect critical infrastructure and to its prohibition authority to address immediate threats to the United States' electric grid. Comments were due by June 7, 2021.

If BPS equipment-sourcing requirements become effective, DOE's approach could mirror CFIUS's restrictions on sourcing of equipment for certain power production projects, especially equipment from China, in the context of CFIUS screening of foreign investment.

International Trade, Compliance and Investment Contract Considerations for Project Developers

Force majeure, change in law, pricing and excused event/delay provisions are the primary mechanisms in offtake, procurement and construction contracts for solar + storage projects to account for effects of changes in international trade and compliance requirements. Ordinarily, these provisions excuse nonperformance when events occur that prevent performance and that a party could not anticipate and over which it had no control. These provisions commonly provide relief to developers under offtake contracts, and equipment suppliers under procurement and construction contracts, from performance in accordance with a schedule under the contract, including guaranteed dates that can be associated with liquidated damages, termination rights or other remedies. Some agreements provide for cost relief, allowing the performing party claiming *force majeure*, change in law or other cost or schedule impact, to pass some or all of the delay or additional cost of the event through to the other party.

To mitigate CFIUS concerns in the context of a foreign investment into one or more solar + storage projects (including portfolios), it is common for project developers to contractually agree with the foreign investor on whether to make a CFIUS filing. If parties agree to make a filing, the parties ordinarily covenant to cooperate on engagement with CFIUS. At the same time, if a developer has adequate negotiating leverage, it can refuse to make CFIUS clearance a closing condition. As an alternative, parties often make CFIUS clearance a closing condition but pre-allocate breakup costs associated with failure to close for lack of CFIUS clearance.

If there is a CFIUS closing condition, a key question is the extent to which, if any, parties must accept any mitigation commitments on which CFIUS makes clearance contingent. The developer would normally prefer "hell or high water" terms such that the foreign investor would be required to accept any such mitigation as a price of securing CFIUS clearance.

ESG

Energy storage creates enormous opportunities in the "E" of ESG (Environmental, Social, and Governance), and positive environmental outcomes also benefit people and society. But energy storage projects contain ESG risks as well as opportunities. One such area of risk lies within the supply chain.

What Types of Risk Might Exist in the Energy Storage Supply Chain?

Forced Labor and Human Trafficking

Raw materials and component parts for energy storage projects are sourced from all over the world, including from jurisdictions with minimal protections for workers. While forced labor and human trafficking have long existed in complex, global supply chains, there is now heightened risk that products sourced from China may contain materials or component parts that are the result of the forced labor of ethnic Uyghur workers from the Xinjiang Uyghur Autonomous Region (Xinjiang). While the technology and retail industries felt this blow first, the photovoltaic solar industry has now entered the spotlight because a dominant portion of the world's polysilicon, used in solar panels, hails from Xinjiang.

Forced labor and human trafficking are prohibited by existing U.S. laws, like Section 307 of the Tariff Act of 1930 (19 U.S.C. 1307) and the Trafficking Victims Protection Reauthorization Act, but regulations and laws specific to forced Uyghur labor in Xinjiang are also emerging. For instance, the Department of Homeland Security has banned imports containing silica-based products from the world's largest metallurgical-grade silicon producer, the Department of Commerce added five Xinjiang-based companies that produce silicon, polysilicon, and related products to its Entity List, the Uyghur Forced Labor Prevention Act passed the Senate in July, and the Corporate Governance Improvement and Investor Protection Act (which would require U.S. publicly listed companies to review and audit supply chains for forced labor and publicly disclose their activities related to Xinjiang) passed the House in June. The Solar Energy Industries Association provides guidance to the industry through its Supply Chain Traceability Protocol.

Conflict Minerals and Child Labor

Wind turbines, solar panels, and energy storage (and specifically, battery storage) equipment require mineral and metal inputs, including traditional conflict minerals like tin, and other high-risk minerals like cobalt. Conflict minerals refers to raw materials that come from areas of conflict, where the conflict affects the mining and sale of those minerals. Mines in areas of conflict are particularly prone to poor wages and working conditions, and sometimes rely upon child labor and other forms of compulsory labor.

In addition to laws prohibiting forced labor and human trafficking, introduced above, SEC reporting companies in the U.S. are also required by Section 1502 of the Dodd-Frank Act to report annually on their use and sourcing of conflict minerals. The OECD Due Diligence Guidance for Responsible Supply Chains of Minerals from Conflict-Affected and High-Risk Areas provides direction to companies sourcing component parts that contain minerals from high-risk areas.

How Are These Supply Chain Isses Affecting Energy Storage Transactions?

Offtake Agreements

Increasingly, offtake agreements for energy storage (such as tolling agreements and power purchase agreements ("PPAs")) and other agreements related to the development of energy storage projects require parties to make representations that their operations and suppliers do not rely upon forced labor. Sometimes, these agreements require a party to represent that forced labor is not used by any direct or upstream suppliers. Some agreements additionally require one party to adhere to the other party's supplier code of conduct, a code which commits a party to certain standards in its supply chain, for instance, regarding labor, health and safety, environment, ethics, and management systems. The language used in such agreements to describe the responsibility of the committing party varies; some examples include "reasonable efforts," "best efforts," or "knowing breach." Contract negotiators should also explicitly address whether new laws that address the risk of forced labor in supply chains entitle the counterparty to relief on schedule or price as a "change in law" or force majeure, or if such changes are excluded.

Storage Equipment Supply Contracts

Companies are also increasingly negotiating and renegotiating their contracts with suppliers to address emerging laws and regulations as well as new guidance for mapping and traceability in the supply chain. Much like offtake and other project finance agreements, equipment supply and related contracts are also increasingly requiring adherence to human rights and environmental standards, such as those contained in supplier codes of conduct, and commitment to processes to achieve those standards.

Although not strictly required by law, supplier codes of conduct are widely used by companies to ensure that certain standards with respect to human rights and the environment are met by their direct and upstream suppliers. Companies sometimes use the Responsible Business Alliance Code of Conduct as the starting point for their supplier code of conduct. Supplier Codes of Conduct often adhere to the United Nations Guiding Principles on Business and Human Rights, thus incorporating due diligence and a grievance or reporting mechanism. For this reason, they are typically part of a broader responsible supply chain or human rights program that includes due diligence, such as third-party audits, questionnaires, mapping and traceability, training, and a reporting mechanism, such as an anonymous hotline.

Import Requirements

A primary way that existing and future supply chain regulations will be implemented is through enforcement at points of entry to the United States. For instance, Hoshine Silicon Industry, the world's largest metallurgical-grade silicon producer, is currently subject to a withhold release order ("WRO") which requires U.S. Customs and Border Protection ("CBP") officers to detain all imports of silicon-based products made by Hoshine as well as goods made in whole or in part with the company's silicon-based materials. In practice, this means energy storage companies importing products containing silica, whether themselves or through a third-party relationship, should collect and maintain documents related to the transactions throughout the supply chain that resulted in the importation, including transaction details among the links in the supply chain, customs entry documents (e.g. CBP Form 7501), and affidavits from each producer in the supply chain that identify where the input materials were sourced, among others. Such documentation will become even more necessary should the Uyghur Forced Labor Prevention Act become law, as it would create a rebuttable presumption that imports from XUAR are prohibited under Section 307 of the Tariff Act of 1930 (19 U.S.C. 1307) and therefore not entitled to entry at any port of the United States. Additionally, although CBP does not generally publicize specific detentions, multiple reports indicate that the WRO on Hoshine has begun to disrupt imports from some of the world's biggest solar panel manufacturers, thus delaying or threatening to delay certain projects.

> In practice, this means energy storage companies importing products containing silica, whether themselves or through a third-party relationship, should collect and maintain documents related to the transactions throughout the supply chain that resulted in the importation, including transaction details among the links in the supply chain, customs entry documents (*e.g.*, CBP Form 7501), and affidavits from each producer in the supply chain that identify where the input materials were sourced, among others.

Of great importance to all solar energy project developers and O&M providers is the petition currently in front of the Commerce Department seeking initiation of circumvention proceeding to determine whether certain major Chinese solar panel producers have been and are circumventing existing antidumping and countervailing duty orders on solar panels from China by shipping Chinese-origin components to Thailand, Malaysia, and Vietnam for further processing into crystalline silicon photovoltaic ("CSPV") cells and modules. If the Commerce Department were to initiate a circumvention proceeding and then issue an affirmative determination of circumvention, then most solar panel imports from Malaysia, Thailand and Vietnam would face the same prohibitively high duties that solar panel imports from China currently face, meaning that such imports would likely plummet. Moreover, Commerce could instruct CBP to collect duties on solar panel imports from Malaysia, Thailand and Vietnam that entered the United States prior to the date of initiation of the circumvention proceeding. Commerce is scheduled to decide whether to initiate a circumvention proceeding by mid-November and, if initiated, the proceeding would last approximately a year. Importers and consumers of CSPV solar panels should assess the potentially dire consequences of this circumvention proceeding, which, if initiated, would be the largest single international trade proceeding in U.S. history.

What Can My Company Do?

Ensure Proper Governance

Given the high level of scrutiny on ESG supply chain issues, companies may ensure proper governance and board oversight of such issues, rather than dealing with them piecemeal. As BlackRock recently recommended, companies can ensure that "the board oversees human rights," including "related policies and processes."

Consider Diversifying Your Supply Chain

Companies with supply chains in high-risk countries or regions may consider diversifying with direct and upstream suppliers that have a lower risk profile. Particularly where there are few alternatives to raw materials or component parts, the first companies to consider diversification will likely be at an advantage.

Establish Supply Chain Responsibility

Once the proper governance structure and supply chain strategy is in place, the company may then ensure proper management of the company's supply chain risks by taking steps to align their program with existing and emerging regulations and laws and by developing responsible supply chain standards and practices.

U.S. REGULATORY DEVELOPMENTS

Updates and Considerations for Solar + Projects

FERC Orders RTOs to Facilitate Participation by Wholesale Storage Projects and Distributed Energy Resources

In 2018, FERC issued Order No. 841, which opened wholesale energy, capacity and ancillary markets for "energy storage resources," defined as any resource capable of receiving electric energy from the grid and storing it for later injection back to the grid. Before Order No. 841, some FERC-regulated RTOs, notably the California Independent System Operator Corporation ("CAISO"), had developed market rules that allowed energy storage resources to participate in wholesale markets. However, Order No. 841 attempted to level the playing field by requiring all RTOs – namely PJM, NYISO, ISO New England Inc. ("ISO-NE"), Midcontinent Independent System Operator, Inc. ("MISO"), Southwest Power Pool, Inc. ("SPP") and CAISO – to revise their tariffs and market rules to accommodate the "physical and operational" characteristics of storage projects.

> This directive drew challenges from state utility commissions and retail-serving utilities, which asserted that FERC lacks jurisdiction to impose these requirements on local distribution systems, but was ultimately upheld by the U.S. Court of Appeals for the D.C. Circuit.[1]

Specifically, Order No. 841 directed these RTOs to develop and implement wholesale market "participation models" that:

- enable storage projects to provide all capacity, energy and ancillary services that they technically can provide;
- permit storage resources to set market-clearing prices, both as wholesale sellers and buyers;
- allow storage projects that sell stored energy back to the grid to purchase power at locational marginal price ("LMP");
- accommodate the physical and operational characteristics of storage projects through bidding parameters or other means;
- allow owners to de-rate the nameplate capacity of their storage projects to meet minimum run-time requirements; and
- establish a minimum size of 100 KW.

Order No. 841 provides that storage resources can sell to, and purchase power from, wholesale RTO markets even if they are interconnected at the distribution level or are configured as behind-the-meter resources. This directive drew challenges from state utility commissions and retail-serving utilities, which asserted that FERC lacks jurisdiction to impose these requirements on local distribution systems, but was ultimately upheld by the U.S. Court of Appeals for the D.C. Circuit.[1] In addition, Order No. 841 provides that RTOs must allow storage resources to manage their own state of charge and must establish bidding parameters or other market mechanisms that reflect state-of-charge characteristics, such as maximum and minimum state of charge, maximum and minimum discharge limits and ramp rates.

With some notable variations, each of the RTOs has developed its participation models in accordance with Order No. 841. CAISO remains a leader in energy storage integration, including with respect to hybrid resources. In contrast, FERC has granted requests from SPP and MISO to delay the effectiveness of their storage participation models. Executives from both RTOs have commented that they have additional work to do before they can fully comply with FERC's directives.

1 *Nat'l Ass'n. of Regul. Util. Comm'rs v. FERC*, 964 F.3d 1177 (D.C. Cir. 2020).

In 2020, FERC issued Order No. 2222, which directed RTOs to develop participation models that will enable aggregators of distributed energy resources ("DERs") to participate in organized energy, capacity and ancillary service markets. FERC defined DERs broadly to include "any resource located on the distribution system, any subsystem thereof or behind a customer meter." Although FERC's definition is resource-neutral, FERC clarified that DERs may include energy storage, distributed generation and demand response. FERC determined that by allowing aggregators to leverage diverse portfolios they could expand the services that they can provide. As with FERC's directives on energy storage resources, RTOs must set a minimum portfolio size that does not exceed 100 KW. RTOs are currently developing draft participation models to address FERC's directives in Order No. 2222.

Orders 841 and 2222 apply only to FERC-jurisdictional RTOs and independent system operators ("ISOs"), which are organized markets subject to FERC jurisdiction. Accordingly, they do not apply to utilities that do not participate in RTOs, primarily utilities in the southeastern United States and in the Pacific Northwest. In addition, they do not apply within the Electric Reliability Council of Texas ("ERCOT") region of Texas.

FERC Considering Wholesale Market Rule Revisions to Integrate Hybrid Resources

Renewable developers are increasingly bidding into FERC-regulated RTO markets new wind and solar projects as hybrid projects that include a battery storage component. In 2020, FERC held technical conferences and collected comments to evaluate current opportunities for hybrid resources to participate in wholesale markets. In addition, FERC directed RTOs to submit reports by July 19, 2021 detailing how each RTO addresses hybrid resources in its interconnection procedures and requirements, market participation models and capacity valuation. Following completion of its review of the RTO submissions and public comments, FERC likely will initiate a rulemaking proceeding to standardize treatment of hybrid resources interconnecting with, and participating in, RTO markets.

FERC Rules That Interconnection Agreements Must Accommodate Stand-Alone Storage and Hybrid Resources

FERC Order No. 845, issued in April 2018, confirmed that storage projects that sell energy to the grid are "generation facilities" and, therefore, can use FERC's pro forma large generator interconnection agreements ("LGIAs"), which are applicable and available to generation facilities with a capacity in excess of 20 MW. Order No. 845 also permits generators with LGIAs or their affiliates to use "surplus" capacity rights in their existing interconnection agreements for storage projects that they or their affiliate add to existing generation. However, simultaneous output by the generator and the storage facility may not exceed the capacity specified in the interconnection agreement, and the interconnecting utility can require installation of governors or other technology to ensure that the LGIA capacity limit is not exceeded. Since they do not have to start at the end of the interconnection queue with a new application, surplus interconnection customers benefit from an expedited interconnection study process. In addition, because interconnection studies assume full capacity output, the additional costs associated with adding new generation ordinarily are low. However, for storage facilities, there can be additional costs associated with upgrades required to accommodate the transmission of charging energy to the project that were not required for the original "generation-only" interconnection. Surplus interconnection rights terminate upon termination of the primary interconnection customer's LGIA. Accordingly, if the primary interconnection customer defaults under its LGIA, the surplus interconnection customer's agreement also is subject to termination.

Storage Facilities Can Qualify for PURPA Pricing Benefits and Regulatory Exemptions

Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), qualifying small power production facilities ("QFs") – generation that uses renewable resources and does not exceed 80 MW – are entitled to compel utilities to purchase their power output and pay avoided cost rates for power. This benefit is especially important in regions where RTO or ISO markets do not exist. QF status also exempts the generation owner and operator from FERC and state utility regulation if the capacity of the facility does not exceed 30 MW. In non-RTO markets, QF status can ensure that a project has a market for its power and can provide more favorable PURPA rates.

FERC has ruled that both stand-alone and hybrid storage projects satisfy the criteria to be QFs if at least 75% of the storage resource's charging energy is sourced from renewable resources. In addition, in 2021, FERC granted an application for QF status for a hybrid project consisting of a solar array with a gross generating capacity of 160 MW and a 50 MW battery energy storage system, where the output of the two components was limited to 80 MW by the capacity of their shared inverters. FERC ruled that, consistent with its traditional approach of determining capacity based on a facility's "send-out capacity," although the hybrid project's gross capacity exceeded 80 MW, the project qualifies for QF status because it cannot deliver more than 80 MW to its point of interconnection.

California PUC Adopts Rules for Multiple-Use Energy Storage

Recognizing that its prior rules for energy storage procurements by California's investor-owned utilities did not address the ability of storage resources to provide more than one type of service,[2] in 2018, the California Public Utilities Commission ("CPUC") adopted rules that classify storage services as either "reliability" or "non-reliability" services and established five "service domains" in which storage services are provided – customer, distribution, transmission, wholesale market and resource adequacy. The CPUC's rules establish a hierarchy for the provision of services by storage projects that are selected in CPUC-mandated RFOs, with priority for reliability services and the ability to provide services having a "higher" priority level than the level of interconnection (with "customer" as the lowest and "transmission" as the highest). As required by the CPUC's order, on March 1, 2018, Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Co. submitted their 2018 Energy Storage Procurement and Investment Plans that implement these requirements for multiple-use storage projects to the CPUC. The CPUC is currently reviewing those submissions.

Storage as Transmission

In addition to providing energy market services, storage projects can provide services that substitute for transmission. FERC's 2017 Storage Policy Statement accordingly permits storage projects to provide both cost-of-service regulated transmission and competitively priced market services. To avoid double recovery from market-based energy sales and cost-based transmission services, RTOs must credit any revenues from market services against any cost-based revenues for transmission services. Several RTOs have implemented or are considering programs to facilitate use of storage resources as transmission.

FERC's 2017 Storage Policy Statement accordingly permits storage projects to provide both cost-of-service regulated transmission and competitively priced market services.

The "storage as transmission" issue is most active in MISO, which revised its tariff in 2020 to address "Storage-as-Transmission-Only Assets." An entity developing a storage resource as a transmission asset in MISO is not subject to generator interconnection procedures. Rather, it must follow MISO's transmission expansion protocols under which MISO will evaluate the project's ability to function as transmission. Storage projects participating in the MISO transmission program cannot participate in wholesale energy, capacity or ancillary service markets. MISO will have functional control of the storage resource, but the owner will remain responsible for purchasing charging energy. Owners of storage resources participating in the MISO program will receive a cost-based rate for the transmission services they provide.

Other RTOs are evaluating similar proposals. PJM stakeholders are considering a proposal by which energy resources could be evaluated as transmission assets through the PJM regional transmission expansion plan process. SPP has not opened a stakeholder process yet, but it has issued a white paper that addresses storage as transmission. Among the issues identified by SPP for further consideration is a concern as to how storage as transmission might affect locational marginal prices in energy markets. There currently is no active discussion regarding storage as transmission in ISO-NE or NYISO.

In 2018, CAISO initiated a stakeholder proceeding to examine "Storage as a Transmission Asset" and is considering innovative approaches to classification and revenue issues. However, that process is currently on hold, and CAISO has not yet developed tariff revisions to address its proposals. In 2018, FERC dismissed a petition submitted by the Nevada Hydro Company, Inc. asking FERC to find that Nevada Hydro's proposed $2b pumped-storage project in California should be classified as a transmission facility. FERC ruled that the petition was premature because the project had not yet been selected by CAISO in its transmission planning process.

2 *Order Instituting Rulemaking to consider policy and implementation refinements to the Energy Storage Procurement Framework and Design Program (D.13-10-040, D.14-10-045) and related Action Plan of the California Energy Storage Roadmap,* Rulemaking 15-03-011, Decision 18-01-003, Decision on Multiple-Use Application Issues (CPUC Jan. 11, 2018).

The issue is similarly on hold in Texas. In 2018, the Public Utility Commission of Texas ("PUCT") dismissed a petition from a distribution utility, American Electric Power Texas, which sought to install a one-MW lithium-ion battery at a cost of $1.6m, rather than adding transmission upgrades at a cost of $6-17m. Texas' Public Utility Regulatory Act prohibits distribution utilities from owning generation. To circumvent that limitation, AEP proposed to classify the battery as a distribution asset, which would mean that the battery's costs would be included in AEP's transmission/distribution rate base, thereby assuring its cost recovery. In dismissing the petition, the PUCT recognized the potential benefits of energy storage as transmission but determined that necessary policies to implement such a proposal were not yet in place. Accordingly, the PUCT staff is currently evaluating potential revisions to its regulations, which will be addressed through a future rulemaking proceeding.

Retail Sales

While FERC regulates wholesale power sales in the continental United States, state commissions regulate "retail" power sales to end users. Most states grant franchises to traditional electric utilities to provide retail service. In some states, these franchises prohibit third parties from selling to retail customers; in others, where there is "retail choice," licensed third-party sellers can supply power to end users. Historically, the question of whether third-party sales to retail customers are permitted has arisen in the context of on-site cogeneration or rooftop solar projects owned by third parties. Some states, such as California, have enacted legislation authorizing such sales if they involve renewable energy or cogeneration; others have ruled that only the franchised utility can serve utility customers (although self-supply is permitted). These same state laws can apply to third-party energy storage sales of power and power-related services to end users, including on-site sales. If the storage device is owned by a third-party provider, state law will determine if there are restrictions, based, for example, on the local utility's franchised service monopoly.

In California, the Public Utility Code expressly exempts on-site solar and combined heat and power projects from regulation based on sales to the "host" customer. However, the exemptions do not expressly include storage. As a result, third-party-owned storage projects serving on-site retail customers must find another exemption from state utility regulation – for example, by showing that their service to the host customer does not constitute service to the general public that triggers utility regulation.

U.S. JURISDICTIONS
CAISO

California continues to lead the country in energy storage procurement, exceeding the legislative target it first set in 2010 with 1500 MW of new storage capacity approved and 506 MW operational as of 2020. A combination of factors drive the state's aggressive goals, including the need to deploy storage as a solution to the "duck curve" effect by balancing daily evening peak load, the planned retirement of once-through cooling base load power plants (including the 2.24 GW Diablo Canyon nuclear plant) and other aging natural gas facilities, and the impacts of climate change, wildfires and other extreme weather events. All of California's investor-owned utilities ("IOUs") and many of its municipal utilities and community choice aggregators ("CCAs") have been actively procuring significant amounts of stand-alone storage and solar + storage projects and products in recent months. Earlier this summer, the CPUC issued its single largest-ever procurement order, requiring Californian IOUs and CCAs to add 11.5 GW of clean energy projects between 2023 and 2026, half of which must consist of long-duration (8 hours) storage and the other half of which must provide firm power.

In this section, we will provide an update on the regulatory initiatives for energy storage in California, including details regarding the distinction between a "co-located" and "hybrid" solar + storage project in the CAISO, and will discuss implications for offtake arrangements. In addition, we will describe recent market developments relating to Resource Adequacy which are exposing some developers to potentially significant change in law/tariff risks in offtake arrangements for stand-alone storage and solar + storage projects.

Regulatory Update – CAISO

The California Independent System Operator Corporation ("CAISO") has been actively developing and implementing wholesale market rules to facilitate integration of energy storage resources. Among the seven U.S. regional transmission organizations ("RTOs") and independent system operators ("ISOs"), CAISO has been a leader with respect to energy storage. In fact, in preparing its 2018 rulemaking order directing ISOs and RTOs to develop participation models to facilitate integration of energy storage resources, the Federal Energy Regulatory Commission ("FERC") modeled many of its directives on wholesale market rules previously established by CAISO. More recently, CAISO has been focused on market enhancements addressing the integration of "hybrid" and "co-located" projects, consisting of traditional generation resources paired with energy storage resources.

In December 2020, FERC accepted revisions to the CAISO tariff that established market participation models for hybrid and co-located resources, which define co-located resources as any generating unit (including storage) with a unique Resource ID that is located behind a single point of interconnection with other generating units. Accordingly, CAISO treats "co-located" projects as two (or more) separate projects, which allows the generation and the storage components to be separately scheduled and dispatched. However, co-located projects cannot schedule energy sales in excess of their aggregate interconnection capacity limits. In contrast, CAISO defines a hybrid resource as a single generating unit of two or more resource types (including storage) that share a single Resource ID behind the same point of interconnection. Unlike a co-located project, a hybrid project participates in the market as a single entity for purposes of scheduling and dispatch.

In 2021, FERC accepted further CAISO tariff revisions clarifying that, under limited circumstances, co-located resources may deviate from CAISO dispatch instructions when meteorological conditions differ from what was forecast, thereby causing a renewable resource that is co-located with a battery to produce more power. In these cases, a battery storage resource could deviate from its dispatch instructions and reduce output to compensate for overproduction of a co-located renewable resource. For example, if a 100 MW solar project is co-located with a 100 MW battery and their shared interconnection capacity is 100 MW, CAISO will apply an "Aggregate Capability Constraint" of 100 MW in dispatching the two co-located resources separately. If CAISO issues a dispatch of 50 MWh each, but greater solar availability allows the solar resource to produce 60 MWh in a scheduling interval, the co-located battery resource could employ control technologies to reduce its output to 40 MWh. CAISO has announced that it will file additional tariff revisions with FERC later this year that will address optimizing dispatch of hybrid resources.

Offtake Considerations

As we referenced in our Offtake section above, certain PPA provisions for solar + storage projects in California will vary depending on whether the solar + storage project is configured as a co-located or hybrid project. For instance, metering provisions of the PPA will typically reflect the utilization of multiple meters for co-located resources, which require separate CAISO revenue-grade meters for each of the storage and solar generation facilities, including meters located at each resource and the delivery point. Multiple metering points should also be considered for hybrid facilities, however, in order to track solar output, solar charging energy, grid charging energy and energy discharged by the storage facility. These measurements will be necessary for calculating accurate compensation for solar output, energy measurements for evaluating solar production guarantees and battery efficiency guarantees, and quantity of RECs generated.

In addition, settlement provisions may vary depending on whether the solar + storage project is co-located or hybrid. As mentioned earlier, a co-located resource must settle, submit outages and receive dispatches for each resource individually with the CAISO, whereas a hybrid resource settles its aggregate output into the CAISO market under a single Resource ID. Despite the difference in CAISO settlement mechanics between co-located and hybrid resources, the solar + storage project operates similarly behind the delivery point in both cases, with solar output used to directly charge the storage facility in both circumstances. The PPA provisions for compensation, scheduling and dispatch will need to account for the applicable settlement approach.

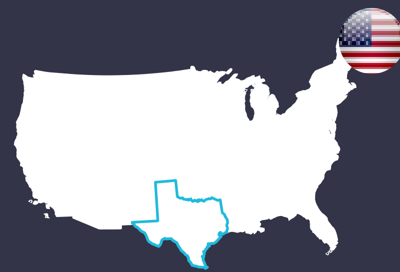
Resource Adequacy Considerations

Load-serving entities ("LSEs") in California are subject to Resource Adequacy ("RA") requirements, under which they must procure sufficient capacity to ensure the grid can reliably satisfy demand. As mentioned in our Offtake section above, stand-alone storage projects and solar + storage projects in California often receive capacity revenue streams based upon their ability to deliver eligible RA (*i.e.*, system, local or flexible capacity) to an LSE, in addition to energy payments based on the energy produced by the solar project or discharged by the storage project. The amount of capacity that a project can monetize is often directly dependent on specific RA metrics. Understanding these metrics—and the potential regulatory changes that may alter their calculation—is crucial to structuring a financeable offtake agreement.

The maximum RA capacity that a resource can hypothetically provide is its Qualifying Capacity ("QC"), which is set by the California Public Utilities Commission ("CPUC") based on a combination of modeled factors (including its Effective Load Carrying Capacity ("ELCC"), which models the incremental load that can be supported by the addition of a resource to the grid). However, the maximum RA capacity of a resource that can be used by an LSE to satisfy its RA compliance obligations is measured by the resource's Net Qualifying Capacity ("NQC"), which reflects the actual performance of a resource based on a test run by the CAISO under summer peak load conditions. As mentioned in our Offtake section above, many energy storage tolling agreements and hybrid PPAs in California either tie the capacity payment calculations to the amount of NQC provided by the project or otherwise impose liquidated damages on the seller in the event of an NQC shortfall.

Recent grid reliability concerns have prompted proposals to change certain RA metrics, including metrics which could decrease the QC or NQC of a stand-alone storage or solar + storage facility. For instance, market participants have discussed the possibility of (i) a downward ELCC adjustment for battery energy facilities with four-hour duration, (ii) merging the existing capacity requirement with an energy requirement and/or (iii) modifying or eliminating NQC altogether in favor of other metrics, such as a "UCAP" metric which would reduce a project's QC based upon historical forced outages. For the reasons described above, one or more of these changes could result in a decrease in capacity payments to sellers under California storage offtake agreements. Many recent offtake agreements limit some of the seller's exposure to this payment risk by including either (a) a compliance expenditure cap that preserves the seller's capacity payments or protects the seller from RA liquidated damages in the event the project's NQC or other RA metric affecting compensation is reduced as a result of a change in law or tariff, or (b) an explicit right to either retain NQC as the metric for compensation under the offtake agreement (subject to protection by the aforementioned compliance expenditure cap and a "gross-up" of the NQC amount for any change in law/tariff risk) or negotiate amendments if a change in law or tariff frustrates the purpose of the capacity payment formulations (*e.g.*, NQC is eliminated and an entirely new and different construct is adopted).

U.S. JURISDICTIONS
ERCOT



Texas Market

While Texas can boast one of the earliest utility-scale battery energy storage projects—the Notrees Battery Storage Project completed by Duke Energy in 2013—deployment of energy storage in Texas has since lagged behind other domestic markets such as California and PJM. Two factors are likely to blame: (1) unlike markets such as CAISO, ERCOT does not have a capacity market, and (2) Texas does not have statutory or regulatory mandates for the procurement or installation of energy storage.

But in spite of these factors, energy storage projects in Texas are poised to take off. While monetizing capacity attributes, such as Resource Adequacy in the CAISO market, is not an available option to ERCOT energy storage projects, Texas battery storage developers have considerable tailwinds due to the tremendous penetration of both solar and wind renewables into the ERCOT grid. First, the growth in intermittent resources such as wind and solar energy projects increases the need for ancillary services to balance the ERCOT grid. Because of their fast ramping capabilities, energy storage projects are increasingly well positioned to monetize those ancillary services in the highly liquid ERCOT market.

> The growth in intermittent resources such as wind and solar energy projects increases the need for ancillary services to balance the ERCOT grid. Because of their fast ramping capabilities, energy storage projects are increasingly well positioned to monetize those ancillary services in the highly liquid ERCOT market.

Second, the increasing transmission congestion caused by wind and solar energy projects creates sometimes significant pricing disparities between various points of financial settlement for financial contracts, *i.e.*, basis risk. Because energy storage projects can arbitrage between low and high energy prices that comprise this basis risk, they are natural physical hedge providers augmenting the economics of wind and solar project developers.

Finally, when paired with wind and solar energy projects, energy storage also aids in monetizing energy generated by these projects that is ultimately unable to be exported to the grid due to interconnection limitations and may give the owner the ability to hedge price exposure under the project's offtake arrangement.

ERCOT Regulatory Considerations

Currently, ERCOT models energy storage resources as both generation and controllable load resources. When a storage resource is available to discharge, ERCOT will dispatch the resource through the same security-constrained economic dispatch model used for generation resources. When a storage resource requires charging energy from the grid, it must submit a real-time energy bid like any other controllable load resource. In addition, storage resources must pay transmission charges for charging energy subject to the interconnecting utility's tariff. Starting in 2024, however, ERCOT will move to a model in which storage resources will submit a single price curve for charging and discharging. To participate in the revised model, storage resources must be able to transition nearly instantaneously between charging and discharging.

Separately, vertically integrated utilities in Texas, *i.e.*, transmission and distribution utilities, are prohibited from owning generation or storage. As a result, independent developers are responsible for financing and developing storage projects. However, developers can make sales to end users through "Retail Electric Providers" ("REPs"). Within Texas, there are a number of independent REPs certified with the Public Utilities Commission of Texas ("PUCT") that are not affiliated with transmission and distribution utilities. Alternatively, a developer can establish and certify its own REP with the PUCT.

ERCOT Stand-Alone Projects Are Ramping Up Fast

Development of stand-alone energy storage resources is rapidly growing in ERCOT. Between 2018 and early 2020, developers and independent power producers began building smaller stand-alone battery projects. However, beginning in 2020, the number of larger-scale, stand-alone battery projects in the interconnection queue expanded (See Edison Energy, Link). In September 2020, there were more than two dozen battery storage facilities that had an expected capacity of more than 100 MW each in the interconnection queue (see Green Tech Media, Link). According to ERCOT, there were 225 MW of installed battery storage as of January 2021 (see ERCOT, Link).

In August 2020, developer Able Grid Energy Solutions began construction on a 100 MW battery project expected to achieve commercial operation in 2021. At the time construction commenced, the project, which is being codeveloped with Map Energy, was the largest stand-alone battery project in Texas. Able Energy is also developing two other stand-alone battery projects with an aggregate capacity of 200 MW.

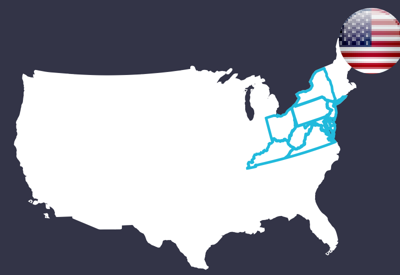
Broad Reach Power, a developer focused on energy storage, is constructing two 100 MW battery storage systems and fifteen 10 MW battery storage systems across Texas, each expected to come online in 2021.

Key Capture Energy similarly expects to complete one 100 MW battery storage system and two 50 MW battery storage systems in 2021, in addition to three smaller battery storage systems Key Capture brought online in early 2020.

ERCOT Is Experiencing an Influx of Hybrid Renewables Plus Storage Projects

Hybrid resources where energy storage is paired with another generating facility, such as wind or solar, are also on the rise in Texas. ERCOT is currently developing rules and procedures for these hybrid facilities in a two-step approach (see ERCOT, Link; Renewable Energy World, Link). First, it is looking at rules that can be implemented under what it calls a "combination model" in which the energy storage system and the generation facility will separately bid in to the market. In the longer term, ERCOT is considering rules that can be implemented under a "single model" structure in which the energy storage system and generation facility are treated as a single resource. ERCOT hopes to introduce these "single model" rules by 2024.

U.S. JURISDICTIONS
PJM/NYISO



PJM Interconnection

Following directives from the Federal Energy Regulatory Commission ("FERC"), discussed below, PJM Interconnection, L.L.C. ("PJM") has implemented revisions to its wholesale market rules to facilitate the participation of energy storage resources in wholesale energy, capacity and ancillary service markets. Energy storage developers have generally supported revisions to PJM's energy and ancillary service markets, but PJM's approach to the PJM capacity market has presented challenges. In 2019, PJM proposed to allow energy storage resources to participate in its capacity market only if they could maintain a minimum run time of ten hours, a proposal that resulted in a dispute before FERC because most other regional transmission organizations ("RTOs") require only a four-hour minimum run time. However, in September 2020, PJM stakeholders approved the use of the Effective Load Carrying Capability ("ELCC") method to measure the capacity benefits of storage resources. The ELCC method measures the performance of a resource during periods when the PJM requires capacity by determining the amount of the resource's capacity that is required to replicate system reliability if "perfect," *i.e.*, 100% reliable, capacity were used instead.

Pursuant to a different PJM policy, energy storage resources that seek to participate in PJM's capacity market are subject to the PJM "MOPR"—PJM's minimum offer price rule. On December 19, 2019, FERC issued an order requiring PJM to apply price floors to capacity auction bids from generation resources, including storage, that receive "state subsidies." FERC defines "state subsidy" broadly to include resources procured through state RPS or other state-mandated resource targets or that receive other state subsidies, such as favorable tax treatment "tethered" to their status as participants in the PJM capacity market. Unless exempted, new (non-grandfathered) storage projects cannot submit capacity auction bids below the default offer prices for storage, which are established by PJM. Existing resources—*i.e.*, storage facilities with interconnection agreements executed on or before December 19, 2019—are exempt from the MOPR. In addition, entities that commit to forego any state subsidies can self-certify for an MOPR exemption. Alternatively, entities can apply for a "Resource-Specific Exception," which sets a price floor based on the unit's actual costs, as presented by the resource owner and approved by PJM. On July 30, 2021, pursuant to suggestions from FERC Chairman Glick, who, as Commissioner, dissented from the MOPR, PJM filed

> Storage projects owned or controlled by generation-only sellers would not be subject to minimum bidding price levels since they would not be motivated to reduce market prices by bidding below cost to benefit associated load.

with FERC proposed changes that would dramatically reduce the effect of the MOPR on storage projects. Under the revised approach, only price offers by sellers associated with load—such as traditional franchised utilities—would be subject to the MOPR. Storage projects owned or controlled by generation-only sellers would not be subject to minimum bidding price levels since they would not be motivated to reduce market prices by bidding below cost to benefit associated load. Also, the MOPR would continue to apply to sell offers that receive "Conditioned State Support," which are benefits provided by a state only if the resource clears the PJM capacity auction. Such arrangements have been deemed to improperly involve states in setting FERC-jurisdictional rates. PJM's proposal is pending before FERC.

New York Independent System Operator

Similar to PJM's MOPR, the New York Independent System Operator, Inc. ("NYISO") has imposed price floors on capacity offers by new energy storage resources offering capacity within the transmission-constrained load zones surrounding New York City. FERC accepted NYISO's price floor proposal in 2020 based on a determination that energy storage resources could suppress capacity prices if deployed strategically. The current FERC chairman dissented from the NYISO proposal and, with the forthcoming Democratic majority at FERC, would have the votes to reverse the FERC's approval. However, because the price floor applies in limited, transmission-constrained areas of the NYISO, there has not been as much pushback to the NYISO price floor policy as there has been to the PJM MOPR.

Separately, the NYISO is preparing tariff revisions that it intends to file with FERC later this year that will introduce market participation rules for co-located resources, *i.e.*, a wind or solar project that is paired with an energy storage resource behind a single point of interconnection with the NYISO grid. Under the NYISO proposal, each co-located resource can be studied as a single facility for purposes of the interconnection process, but each component (*e.g.*, solar and storage) will have its own values for the amount of energy and capacity that it can inject into the NYISO system. The two components will participate as separate resources for purposes of bidding, scheduling and settlement within the NYISO markets. In a separate stakeholder proceeding, NYISO is developing further tariff revisions to address hybrid resources that would be studied and function as a single facility.

INTERNATIONAL JURISDICTIONS
UNITED KINGDOM

A Booming Market

The U.K. storage market is in the middle of a boom. Recent data from the trade association RenewableU.K.[1] shows that, in the U.K.:

- 1.1 GW of storage capacity is now operational;
- 0.6 GW is under construction;
- 1.6 GW is in the planning system;
- 8.3 GW is consented; and
- 4.5 GW is in early-stage development.

In total, more than 16 GWs of battery storage capacity is either operating or planned across 729 U.K. projects. An additional 6 GWs of energy storage from liquefied and compressed air, pumped hydro, flywheels and gravity-based technology is operating, under construction or being planned, bringing the total U.K. energy storage pipeline capacity to more than 22 GWs. There are question marks about whether all of this planned capacity will be built out, but, nevertheless, it is a sign of a confident and maturing storage market in the U.K..

This is all the more remarkable when compared to the status of storage in the U.K. when the previous volume of this paper was published in 2018. At that time, energy storage was a nascent industry in the U.K.. Projects were coming forward, but there were many hurdles to overcome in terms of regulation, economics and bankability. At that time, widespread doubts existed amongst market participants about whether storage would ever be a significant feature of the U.K. energy mix (beyond meeting a relatively modest demand for frequency response).

Trend Towards Co-location

A notable trend of the U.K.'s energy storage landscape is the ever-strong interest in co-located projects (particularly wind + storage and solar + storage). Many renewables developers are either considering retrofitting storage to existing sites or making sure that new developments are "battery ready."

Co-location offers clear economic benefits not least in using preexisting grid connections (which is a big issue for stand-alone battery developments – which face high costs, long lead times and expensive grid security costs to carry). On-site benefits may also be available to relevant projects.

What Has Driven the Storage Boom?

Key drivers of the recent boom have been:

- the simplification of the regulatory framework;
- a quicker and easier planning process; and
- a clearer route to stable, long-term revenues.

Regulatory Framework

Licensing was historically a pain point for many storage investors. U.K. primary legislation does not explicitly capture energy storage technology, which has historically created uncertainty about how the law applies.

However, in October 2020, Ofgem (the government regulator for gas and electricity markets in Great Britain) published an update confirming that storage activities would be addressed in generation licenses to make the applicable regulatory position clearer. The update also confirms that storage projects will be subject to a Standard License Condition E1 ("Requirement to Provide Storage information") in order to (i) ensure that license holders provide accurate information regarding their electricity storage facility to their relevant suppliers, and (ii) facilitate the correct identification of licensed facilities as "electricity storage" and the correct calculation of certain charges (although, notably, the condition provides for exemptions from payment of final consumption levies where the electricity imported is used only for electricity storage).

Planning

The planning process for storage projects has also been simplified. Until recently, one of two separate planning regimes would apply according to the project's size:

(i) for projects under 50 MW, local planning laws would apply pursuant to the Town and Country Planning Act 1990; whereas

(ii) for projects of 50 MW or more, these would be classified as Nationally Significant Infrastructure Projects ("NSIP"), meaning that planning would need to be approved via a separate procedure managed centrally by the government, leading to increased costs and, often, delays.

1 *Renewable UK* https://www.renewableuk.com/.

In July 2020, however, battery storage projects were taken outside of the remit of the NSIP regime. This means that projects at or above 50 MW can now take advantage of the quicker, simpler local planning regimes instead. The effects have been immediate: three projects with a capacity of 100 MW each have since applied for approval to local planning authorities. Although this should speed up the process, planning uncertainties still remain at the local level. We understand that the Department for Business, Energy & Industry intends to issue further guidance to local authorities specifically to address these potential uncertainties, which will further improve the situation for developers.

Revenue

There have also been welcome developments relating to the revenue streams which are available to U.K. storage assets.

Traditionally, building the investment case (and banking case) for a U.K. battery asset has been complicated. This has required understanding of a complex 'revenue stack' built of many separate revenue streams (usually providing only short-term income). It has been notoriously difficult to obtain financing for battery storage projects (particularly project finance on attractive terms and with attractive levels of gearing) because of the lack of stable, long-term revenue streams.

However, the sector may be at a turning point because:

(i) 'flex' or 'optimization' power purchase agreements are on the rise. Under these agreements, the generator gives exclusive rights to the offtaker to dispatch the project to optimize revenue. It is sometimes possible to fix an element of the revenue, such as by guaranteeing a minimum income (*e.g.*, the day-ahead auction price) or a fixed capacity payment. This creates a structure similar to floor prices in traditional PPAs, which is easier to bank;

(ii) the Capacity Market remains a potential source of revenue and prices look to be trending upwards. However, the application of derating factors has negatively affected available revenues for short-duration storage; and

(iii) National Grid is working on a new menu of frequency response products, which will be available to storage assets in due course, with Dynamic Containment which had a 'soft launch' in October 2020. Dynamic Containment is designed to operate post-fault (*i.e.,* after a significant frequency deviation) in order to meet the most immediate need for faster-acting frequency response. It is expected that battery storage projects will be the principal and most suitable providers for this service. In a recent frequency report, National Grid described the first few months of using Dynamic Containment as a success and expected Dynamic Containment requirements per month of 1.4 GWs for May, June, August and September. In the latest Dynamic Containment auction, 396 MWs of battery storage capacity won contracts, including players such as Habitat Energy, Flexitricity, Tesla Motors, Arenko, Zenobe Energy, EDF Energy and U.K. Power Reserve.

What Does the Future Hold for U.K. Energy Storage?

- **Supportive Policy Environment.** Battery storage was recognized by the U.K. government as being an important tool to help reach the U.K.'s net zero target by 2050 in its Energy White Paper (published December 2020). We therefore expect continued development of policy to facilitate storage projects.
- **Economic Drivers.** Wholesale prices, balancing prices and capacity market prices may well continue to rise as the U.K. system continues to get tighter, with further closures of coal and nuclear in the pipeline.
- **Diversification of Storage Technologies.** There are reasons to be optimistic about the prospects of non-battery, alternative storage technologies.

  For example, Highview Power and Carlton Power have launched a joint venture to build and operate the world's first commercial liquid-air energy storage facility in Carrington, U.K.. The project (50 MW/250 MWh) is expected to enter into operation in 2023 and will receive government support in the form of a £10m grant.

  As in other markets, there is also huge interest in green hydrogen as storage technology and "fuel of the future."

Conclusions

The U.K. is becoming an important market for energy storage. Despite remaining challenges for the sector, there is a clear sense of optimism that the U.K. storage market will continue to accelerate and that energy storage will play a significant role in the U.K.'s journey to net zero by 2050.

INTERNATIONAL JURISDICTIONS
JAPAN

Japan's battery storage market is expected to grow rapidly. The prime minister declared in October 2020 that Japan will achieve carbon neutrality by 2050, and the nation is currently undertaking drastic reforms related to supporting measures for renewable energy and the grid system to further expand renewables, including the development of storage.

Behind-the-Meter (BTM) Storage

BTM storage systems have been available to consumers in Japan for some time, and as of 2019, Japanese households had installed approximately 2.4 GWh in storage battery capacity.[1] C&I solar installation schemes are recently gaining popularity, and some projects have installed storage batteries together with photovoltaic facilities. Demand for BTM storage battery installation is likely to remain strong because of the nation's unprecedented growth in interest in the environment.

Front-of-Meter (FTM) Storage

A. Hybrid Projects

Japan has so far seen 1.2 GWh of FTM storage battery installed for hybrid projects or for grid use as of 2019[2], and further growth is expected.

FTM storage in Japan consists mostly of on-site storage systems installed on the project sites together with energy production facilities. After Japan introduced the Feed-in-Tariff ("FIT") scheme in 2012, some projects installed on-site battery storage in hopes of obtaining additional earnings by selling battery-stored electricity that is produced at peak times and discharged after peak-out. With battery prices continuing to fall, renewable project owners considered installing batteries to generate more income after commencement of operations. This has been commercially impractical for existing projects under the current FIT scheme, however, since such installation, in principle, constitutes a material change that triggers the applicable FIT price reduction. As a welcome update, the government has announced that for projects that are newly approved under the Feed-in-Premium ("FIP") scheme in FY2022 and beyond, any future addition of batteries will not constitute a cause for reduction of the original FIP price.

The FIP scheme will be effective in April 2022 to promote market integration of renewables. FIP-approved projects will be entitled to receive a premium from the authorized third-party organization in addition to their earnings from market transactions (whereas FIT projects are entitled to gain income from the sale of electricity at fixed prices regardless of market price fluctuation), and demand for peak shifting is therefore likely to increase further.

B. Stand-alone Projects

Some transmission and distribution services operators ("TDSOs") in Japan have installed battery storage at their substations on an experimental basis for the purpose of stabilizing frequency fluctuation or balancing demand and supply in the region. For instance, storage batteries were installed at two substations (20 MWh and 40 MWh) in the Tohoku area, a 60 MWh storage battery was installed at a substation in the Hokkaido area and a substation with a 300 MWh storage battery was constructed in the Kyushu area. Most recently, since 2017, Hokkaido Electric Power Network, Inc. ("Hokkaido NW"), a TDSO covering the Hokkaido area, has been conducting a process accepting grid connection application for potential wind projects wishing to be connected on condition of covering the cost of FTM storage battery installation by Hokkaido NW. The phase for the first group of wind projects has been completed, and 51 MWh storage battery is expected to be constructed by 2022. Hokkaido NW will start the phase for the next group of wind projects in July 2022, and further installation of storage batteries is expected to come.

FTM stand-alone battery storage is still new in Japan. It has been unclear whether operators other than TDSOs can operate stand-alone storage projects and what regulations would be imposed under current Japanese law. However, in order to encourage market integration and further the introduction of renewables, the government now recognizes the importance of providing flexibility and promoting aggregation businesses. Amid various reforms, the Japanese government has now started discussions to clarify the legal status of such battery storage and thereby enable independent power producers to operate stand-alone storage projects. Tesla Motors Japan announced in August 2021 that it will partner with Japanese electricity retailer to build a 6 MWh storage facility connected to the grid in Hokkaido. As such, regulators and businesses are gearing up for the future of battery storage.

1 Mitsubishi Research Institute, Inc. "The Understanding of the Current Status regarding Storage Systems" (*chikuden sisutemu wo meguru genjou ninshiki*), November 19, 2020, p.14.
2 *Ibid.*

INTERNATIONAL JURISDICTIONS
ITALY

The lack of legal definition and regulatory uncertainty regarding battery storage has resulted in a significant delay in the development of storage capacity in the Italian market as compared to the United States and certain other jurisdictions. We expect, however, electric storage systems to play an increasingly important role in the power generation sector, given the necessary and continuous growth of installed capacity of non-programmable renewable (wind and photovoltaic solar) resources in Italy and their rapidly decreasing costs. In recent years, storage installations have been made in Italy, and the Italian government is taking action to help promote and facilitate the growth of energy storage in the country, boosted in part by the increase in domestic renewable energy generation.

For instance, Terna S.p.A. has planned the installation of new storage technologies directly connected to the National Electricity Grid. As part of these developments, Terna S.p.A. has planned a 40 MW storage system installation program with the aim to increase the stability and the security of grids in Sicily and Sardinia. Enel S.p.A. is also involved in the development and installation of storage systems in Italy. For instance, Enel recently installed a 1 MW/2 MWh battery storage project co-located with a photovoltaic plant interconnected to the grid in Catania (Sicily). In addition, Enel S.p.A. recently developed an 18 MW wind plant equipped with 2 MW/2 MWh of lithium-ion batteries, which is the first wind plant integrated with a storage system and connected to the grid in Italy.

Moreover, the Italian National Recovery and Resilience Plan ("PNRR"), submitted to the European Commission on April 30, 2021, includes several projects involving storage systems, including the "Isole Verdi" project whose aim is to make 19 small Italian islands self-reliant and "100 percent green" through investments in power grids, infrastructure, renewable energy integration, smart grids and energy storage systems. From the perspective of Italy's legal framework and its development in recent years, it is worth mentioning resolution no. 574/2014 of November 20, 2014, under which the Italian Regulatory Authority for Energy, Networks and Environment ("ARERA") formally defined storage systems as "a set of devices, equipment and system of management and control, functional to absorb and release electricity, designed to operate continuously in parallel with the electricity network. The storage system can be integrated or not with a production plant."

In addition, European regulations and policies on climate change and renewable energies have strongly influenced and changed Italy's legal framework relating to storage systems. Pursuant to the Governance of Energy Union Regulation (EU) 2018/1999, on December 2019 the Italian Government submitted to the EU Commission its Integrated National Energy and Climate Plan ("PNIEC"), which is the plan containing Italy's long-term energy strategy, to be submitted by each EU State member to the EU for its approval. In the PNIEC, it is expressly stated that "the main objective [in the electricity sector] is to implement new market instruments, in order to channel investments towards new storage systems and generation capacity and to promote (as in the case of the market for network services) a progressively more active role for demand and other resources that can support adequacy, on the basis of pre-established standards."

> Italy is committed to installing 10 GWs of new storage systems before 2030, of which 4 GWs will be in the form of small batteries and the rest divided between pumping and large electrochemical systems.

Indeed, the PNIEC foresees a major development of storage capacity, which will be gradually but increasingly targeted towards "energy-intensive" solutions, in order to limit the phenomenon of over-generation of renewables and to promote the attainment of renewable energy consumption targets. In particular, Italy is committed to installing 10 GWs of new storage systems before 2030, of which 4 GWs will be in the form of small batteries and the rest divided between pumping and large electrochemical systems.

In order to help promote substantial development of electrochemical storage projects consistent with the goals set in the PNIEC, Law Decree no. 76/2020 aims at simplifying the authorization procedures and providing more favorable regulation by classifying electrical storage systems connected to power generation plants as "related facilities" ("opere connesse") to the renewable plants. As "related facilities," storage systems are authorized to operate together with the generation plants they relate to, through a procedure called "sole authorization" ("autorizzazione unica"), pursuant to Article 12 of the Legislative Decree no. 387 of 29 December 2003.

The procedure is even more simplified if the storage system is to be built and connected to a generation plant already built and in operation. If the storage facility, regardless of its capacity, requires an expansion of the existing site utilized by the generation project, the storage facility can be authorized through the "variations procedure" pursuant to Article 12, paragraph 3 of the Legislative Decree no. 387 of 29 December 2003. On the other hand, if the storage facility does not require such expansion, then (i) if it has a capacity above 10 MWs, it can be authorized through the Simplified Authorization Procedure ("PAS") pursuant to article 6 of the Legislative Decree no. 28 of March 3, 2011 (Article 62) and (ii) if it has a capacity below 10 MW, it falls within the so-called "free activities" and it does not require the issuance of any authorization title (Article 62).

However, according to Article 31 of the new Conversion Law no.108 of July 29, 2021, of the Law Decree no. 77 of May 31, 2021, the storage system connected to a plant is authorized through PAS when the plant is already built or authorized, even if it has not yet come into operation and, of course, if the storage system does not involve the occupation of new areas. Therefore, the authorization procedure for a storage system is even simpler than that set by the previous simplification Decree no. 76/2020 in case the storage system is ancillary to a plant (regardless of the power capacity of the storage system or the plant).

The Law Decree no. 76/2020 also provides additional simplification measures for:

(a) storage facilities located within industrial areas;

(b) stand-alone plants and other storage facilities located within areas already occupied by fossil-fueled electricity production plants with a capacity greater than to 300 MWs in operation; and

(c) coupled storage facilities to be operated in combination with plants for the production of electricity from renewable sources.

Focusing on "stand-alone" electrochemical storage plants, it is also worth mentioning that Article 31 of Law no. 108 of July 29, 2021, states that such type of storage systems, together with their connection facilities, shall no longer be submitted to the Environmental Impact Assessment procedure ("EIA"). Indeed, "stand-alone" storage plants usually have no environmental impact since they are mostly located inside sheds.

In light of that outlined above, Italy continues to take additional steps in efforts to satisfy the goals set forth in the PNIEC. In addition to Law Decrees no. 76/2020 and no. 77/2021, Law Decree no. 34/2020 (a.k.a. "Decreto Rilancio") introduced a "Superbonus 110%," namely a tax deduction equal to 110% to be applied to those expenses borne for specific interventions, such as the installation of photovoltaic plants and storage systems (*i.e.,* 110% tax deduction in five years).

It is important to bear in mind that pledges contained in the PNIEC must be revised according to the new European Union goal to reduce EU GHG emissions by at least 55% by 2030, compared to 1990 levels. Therefore, Italy is expected to continue setting ambitious commitments to both renewable generation projects and energy storage systems.

INTERNATIONAL JURISDICTIONS
SPAIN

Currently, the utility-scale power storage installed capacity in Spain is limited to the 5 GWs of pump-fed hydroelectric power plants, but a significant number of storage projects are under development by a varied group of sponsors in line with the strategic priorities set by Spanish authorities. Power storage is viewed by the Spanish authorities as a key element to achieve the transition to an emission-neutral economy and the effective integration of renewable energies in the Spanish power system, and to guarantee the safety, quality and sustainability of power supply and the efficiency of the overall power system.

The long-awaited definition of power storage activity in Spanish legislation has been recently introduced by the Royal Decree-Law 23/2020 (in force as from June 25, 2020), that partially transposed Directive (EU) 2019/944 of June 5, 2019, into the Spanish legal framework regarding energy storage and aggregation. This new regulation has also included certain measures to foster the introduction of power storage, in particular, permitting the hybridization of existing power production facilities without requiring new grid capacity permits.

In particular, this regime subjects storage facilities to the same grid access procedures and requirements established for production facilities (applications for access and connection to the grid for power storage facilities will be considered equivalent to the same applications relative to power production facilities) and entitles storage facilities to participate in capacity auctions in certain nodes of the transmission grid in the same conditions as renewable energy production facilities.

Accordingly, the new grid access regime (provided by Royal Decree no 1183/2020 and Circular CNMC 1/2021) constitutes the legal framework for the access and connection of power storage facilities to the transmission and distribution grids, introducing them expressly under its scope. In particular, this regime subjects storage facilities to the same grid access procedures and requirements established for production facilities (applications for access and connection to the grid for power storage facilities will be considered equivalent to the same applications relative to power production facilities) and entitles storage facilities to participate in capacity auctions in certain nodes of the transmission grid in the same conditions as renewable energy production facilities. These new regulations further define the hybrid facilities regime according to the fostering mechanisms described above.

Royal Decree 960/2020, on the economic regime of the renewable energies for electricity production facilities, has included within its scope renewable energy facilities hybridized with energy storage, which entitles these installations to participate in auctions to access a remuneration scheme consisting in the award of a long-term fixed price (guaranteed by the State) for the sale of the power produced by the relevant installation in the wholesale power market.

Spanish framework on the Integrated National Energy and Climate Plan 2021-2030 ("Plan Nacional Integrado de Energía y Clima 2021-2030", the "Spanish PNIEC"),[1] and its developing initiatives also include measures intended to foster power storage in Spain:

(a) The Spanish PNIEC seeks to set the basis for the fulfillment of the carbon emission reduction objectives set for the current decade by, among other measures, the decarbonization of the energetic and industrial systems. This objective hinges on a high penetration of renewable energies (by 2030, 74% of the power generation intends to be produced through renewable energy sources as well as 42% of the final use of energy) and the boost and optimization of storage systems through different technologies to enable more flexibility in the management of power production and demand.

(b) Law 7/2021, of May 20, 2021, on Climate Change and Energy Transition[2] introduces the objectives with respect to climate and energy for 2030 and 2050, providing a stable institutional framework to implement the necessary actions for their achievement. Among other measures, it regulates the framework to foster innovation in the area of renewable energies (including storage technology) and requires that, in a 12-month period as from its entry into force, the government and the CNMC (the Spanish watchdog) submit a proposal to introduce modifications to the legal framework to bolster, among other matters, the energy storage system.

(c) The "Decarbonization Strategy in the long-term"[3] (approved by the Spanish Government on November 3, 2020), implementing the Spanish PNIEC, set out: (i) the opportunity for the national industrial sector to use the energy storage along the entire value chain; (ii) on the power sector, the energy storage systems will be essential to guarantee the effective integration of the renewable energies.

(d) In order to achieve the abovementioned targets, the Spanish government has recently approved on February 9, 2021 the "Energy Storage Strategy[4]" in order to guarantee the effective deployment of the energy storage as an enabler of the energy transition to move towards climate neutrality.

Both the Energy Storage Strategy and the Decarbonization Strategy foresee in the long term increasing energy storage capacity in Spain from 8.35 GWs to 20 GWs by 2030, and to 30 GWs by 2050, including both large-scale or "in front of the meter" (through the hybridization with renewable energy production facilities) and distributed or "behind the meter" energy storage. Additionally, this document identifies the challenges that energy storage represents and defines the applicable measures to ensure its effective deployment in Spain.

The Spanish government has announced that this strategy puts Spain at the forefront of battery storage development in Europe. The strategy includes 10 action lines and 66 measures addressing, among other things, the involvement of the storage in the energy system, the circular economy, the development of new businesses models, the harnessing of the storage as the key element for the technological development in the islands and isolated zones, the boost of R&D or the elimination of administrative barriers.

Lastly, the participation of power storage facilities in both the supply and demand side of the balancing processes has been introduced in the Spanish legal framework by the amendment of the power market rules in October 2019 and of several operating procedures ("OP") for the power system in December 2020.

In conclusion, the main elements of power storage regulations in Spain have been recently enacted, with recent developments on those elements directly related to the development process and even the more technical rules for the integration of these kinds of facilities in the system. In doing so, the Spanish legal framework has fully developed the necessary elements and provisions for the successful development of energy storage facilities. Moreover, in the coming months and years, new regulations are expected to be passed to foster the activity required to fulfill the goals established in the Spanish PNIEC and its developing strategies.

1 Sent to the European Commission on March 31, 2020, and final adaptation approved by the Spanish government on March 16, 2021.

2 Ley 7/2021, de 20 de mayo, de Cambio Climático y Transición Energética.

3 Estrategia de Descarbonización a largo plazo 2050.

4 Estrategia de Almacenamiento Energético.

HYDROGEN: A NEW FRONTIER

Hydrogen is widely described as the next frontier for energy storage. Green hydrogen in particular—that is, hydrogen produced from the electrolysis of water using solar, wind or other renewable energy—has remarkable potential for use as general fuel, to power vehicles or for energy storage. In energy storage applications, one of the basic propositions has been to use low-cost or surplus renewable energy in hydrogen electrolysis, store the hydrogen produced in tanks, underground caverns or other vessels, and then run the hydrogen through fuel cells to convert it back to electricity during periods of high energy demand on the grid.

This use of hydrogen in this manner for storage, known as "power-to-gas-to-power," not only provides much more flexibility in use and longer duration storage than traditional lithium-ion batteries—the most common storage technology in new projects today—but is fully carbon neutral and will help achieve carbon reduction goals.

The issue, of course, is that power-to-gas-to-power hydrogen projects are very expensive in today's market. It is expected that hydrogen project costs will decline over the next couple decades, both due to reductions in equipment costs and increase in governmental project subsidies. Hydrogen production projects coupled with hydrogen offtake contracts for use as fuel in transportation vehicles are becoming more common. However, given the high costs today, most projects proposed to date involving power-to-gas-to-power technology are small, experimental or in the nature of R&D.

Among the most talked-about structures for these projects involves the co-location of a renewables generation project with a hydrogen project. With the expectation that these projects will become more common in the years to come, we set forth below a few of the lessons learned in structuring the key commercial contracts for these projects:

- **Basic Contract Structure:** Although structures vary, most power-to-gas-to-power offtake contracts between a project sponsor/owner and a load serving entity or other offtaker are suitable to be structured such that:

  (i) the sponsor develops, constructs, owns and operates a co-located renewable generation facility (whether solar, wind, etc.) along with a hydrogen energy storage facility comprised of a hydrogen electrolyzer, a hydrogen storage tank and a hydrogen fuel cell;

  (ii) the offtaker purchases the energy produced by the generation facility as well as the energy storage services provided by the hydrogen storage facility, including the right to direct "charging" of the storage facility (by generating hydrogen in the electrolyzer) and discharging the storage facility (by directing hydrogen to the fuel cell), along with the overall facility's capacity attributes, ancillary services, green attributes and other products.

- **Contract Compensation:** Compensation structures vary, however, based on the above-described structure, the offtaker would typically pay:

  (i) a $/MWh rate for all delivered energy whether delivered to the grid or the electrolyzer; and

  (ii) a $/kW/month capacity payment for the hydrogen facilities and also potentially a variable charge, depending on various use cases of the hydrogen facilities.

- **Key Performance Guarantees:** As with renewables plus battery energy storge facilities, an offtaker with a renewables plus hydrogen storage facility will ordinarily expect guarantees and liquidated damages related to:

  (i) annual renewable energy output;

  (ii) storage facility availability and round-trip-efficiency;

  (iii) storage facility power capacity, energy capacity, and charge/discharge rates; and

  (iv) other similar metrics.

- **Other:** The offtake contract should contain all other customary provisions, including, for example, construction schedule and completion guarantees, forecasting and scheduling, credit support, events of default, indemnities, and other customary and miscellaneous provisions.

Given the experimental nature and small size of most power-to-gas-to-power projects, in our experience—and in the spirit of collaboration and R&D—sponsors can often negotiate sponsor-friendly provisions with respect to defaults, damages caps and similar provisions.

As we look out over the next five years in this era of our clean energy transition, requiring more and more energy storage, the evidence is clear that stationery stand-alone storage projects and renewables generation + storge projects will be dominated by battery storage technologies. Hydrogen will certainly increase in use in transportation, particularly long-haul transportation applications. However, until project costs for power-to-gas-to-power projects are significantly reduced, we would expect to see such projects primarily where their much higher costs are outweighed by critical needs for the longer-duration storage they provide.

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If you have any questions or comments on this report, please feel free to contact any of our editors or the respective authors of each country report.

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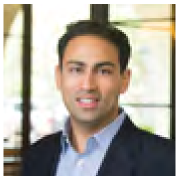

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Hydrogen: A New Frontier

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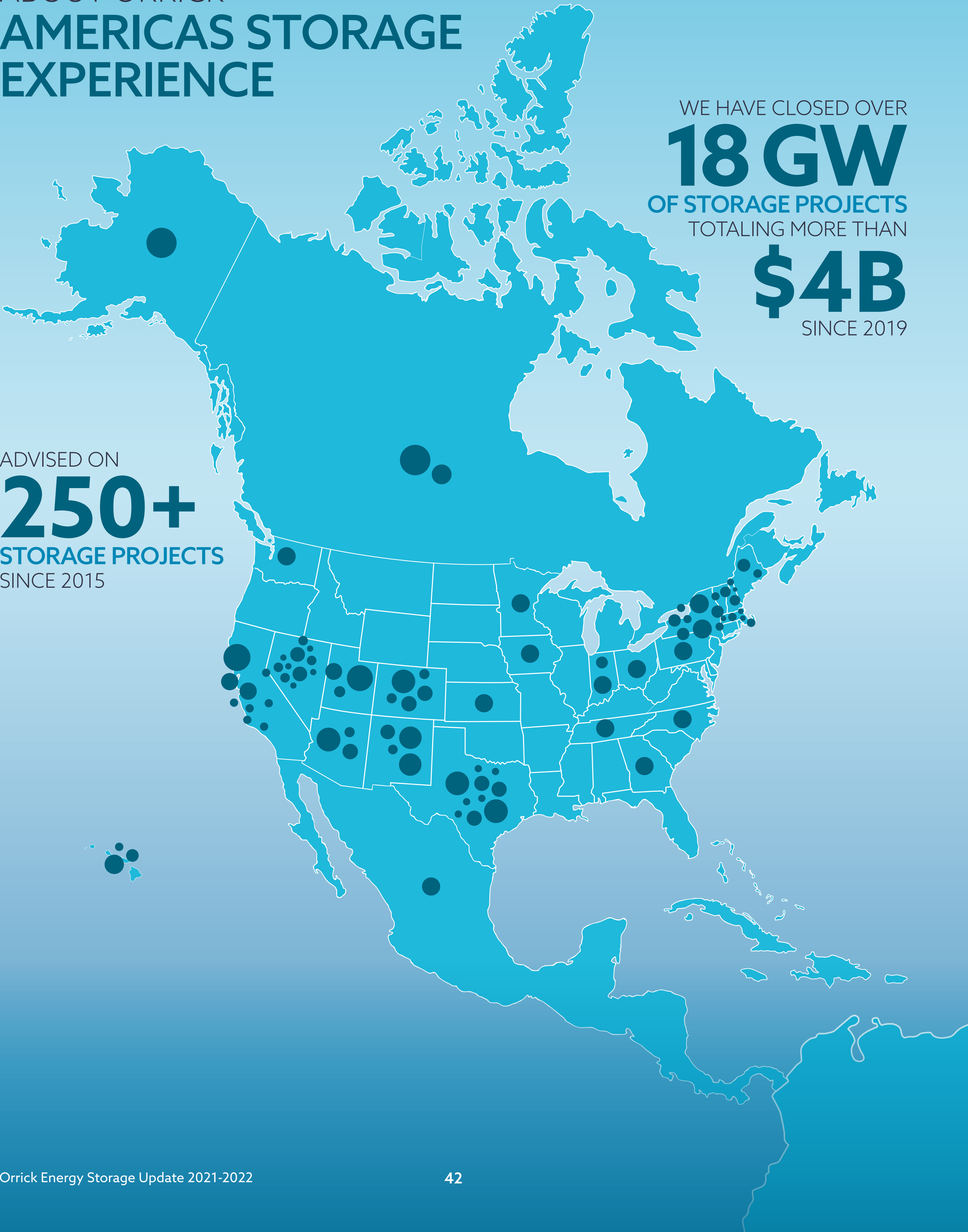

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Energy and Infrastructure, *2021*

> **IF THERE IS A BIG DEVELOPMENT IN RENEWABLES, THEY ARE IN IT SOMEWHERE; THAT COVERAGE IS INCREDIBLY VALUABLE.**
>
> *CHAMBERS AND PARTNERS*, 2021

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