

ENERGY STORAGE UPDATE 2018

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Battery energy storage is the most significant development for the electric grid since the explosive growth in renewables deployment over the past decade. Battery storage projects are gradually becoming mainstream in California, and efforts to promote energy storage are moving rapidly throughout the country, with particular growth in New York, New Jersey and Massachusetts. These developments are driven by a host of factors, including critical needs to integrate intermittent solar and wind generation into electric grids to achieve sustainability goals, continuing decreases in the capital cost of new battery systems, favorable federal and state regulatory and procurement climates, certain tax benefits, and greater demands by end-use customers for resource choice and flexibility in a quickly evolving energy market. This boom in battery storage presents a tremendous opportunity for market participants, including developers, utilities, lenders, investors, contractors and equipment vendors. At the same time, the opportunities have created a unique set of commercial and legal issues and challenges for participants.

INTRODUCTION

Focusing on these opportunities and challenges, this article is the third in Orrick's series of articles covering the development of the energy storage industry. Based on our experience in the past few years engaged on transactions in this rapidly growing market, both inside and outside the United States, this article provides a current update on the following important topics:

- **Commercial Factors for Project Viability and Financeability:** Key commercial factors that ensure battery storage projects are viable and financeable, which in the case of non-utility owned projects is the existence of a long-term offtake revenue contract to provide a steady stream of project cash flow, and in the case of both utility and non-utility owned projects, the existence of EPC (or vendor) performance guarantees providing unique battery-specific acceptance tests and continuing guarantees to ensure proper construction and long-term performance.
- **Battery Storage Contract Structures and Issues:** Key contract and commercial structures being used to implement battery energy storage projects in the U.S. market, including energy storage tolling agreements, capacity sales agreements, hybrid power purchase agreements, utility services agreements and host customer agreements, and a description of the key issues involved with those structures.
- **Regulatory Developments:** Key federal and state energy regulatory developments that are facilitating the deployment of energy storage systems.
- **ITC and Tax Issues:** Key tax issues associated with battery energy storage projects, including the rules establishing eligibility of battery systems for the federal investment tax credit when the systems are integrated with solar or other renewables generating projects.
- **State Procurement Developments:** Key developments in state level procurement and other laws that are promoting battery energy storage in a growing number of states.
- **Storage Market in the United Kingdom:** Key developments in the deployment of battery energy storage projects in the United Kingdom.

BACKGROUND

The storage industry has recently been boosted by the successful completion of the first wave of non-recourse battery energy storage project financings and the increase in utility procurement of battery storage projects and products. Since publication of our earlier energy storage articles, private developers have successfully closed hundreds of millions of dollars of financings for large battery projects. At the same time, utilities have procured hundreds of megawatts of utility-owned battery projects through EPC, BOT or similar contractual acquisition structures and have executed numerous contracts for battery project services and products.

Of course, the successful development and financing of any type of energy or infrastructure project requires many different building blocks, including site control, permits, interconnection, regulatory exemptions, EPC, O&M,

PPA/offtake revenue contracts, and others. Although each of these is important, our experience has revealed that the most unique and critical issues to ensure the viability and financeability of battery storage projects arise primarily in two areas. For non-utility owned projects, the first area of focus is a dependable offtake revenue contract to provide a steady stream of project cash flow. These contracts have a number of structures, and involve many issues unique to battery storage technologies. The second area involving unique issues, for both utility and non-utility owned projects, is the existence of EPC, installation, long term services/O&M or other project contracts that combine battery system acceptance tests and continuing performance guarantees to ensure proper construction and long-term performance.



OFFTAKE REVENUE CONTRACT STRUCTURES AND ISSUES

Introduction

The variety of offtake revenue contracts for battery storage projects has expanded rapidly since we published our first article on the energy storage industry in 2014. Today's offtake revenue contracts for the sales of products and services from battery storage projects generally fall into two categories. The first category relates to projects which are connected to the energy grid "in front of" a customer's revenue meter ("front-of-meter" contracts), including energy storage tolling agreements, capacity sales agreements and hybrid power purchase agreements. The second category relates to projects which serve the electric load of a customer "behind" the customer's revenue meter ("behind-the-meter" contracts), including utility services agreements and C&I host customer agreements. We evaluate below each type of contract and some of the key issues often negotiated between the contract parties.

Key Contract Structures and Issues

Front-of-Meter Contract Structures

Offtake revenue contracts for front-of-meter battery storage projects usually take one of three forms: the energy storage tolling agreement, the capacity sales agreement or the hybrid power purchase agreement (PPA). The energy storage tolling agreement and capacity sales agreement are similarly structured and typically govern the sales of products and services from a stand-alone battery storage project. In contrast, the hybrid PPA applies to a renewables or conventional energy generation project (e.g. solar, wind, gas or other project) integrated (and typically co-located) with a battery storage project.

1 ENERGY STORAGE TOLLING AGREEMENT

The energy storage tolling agreement is structured like a standard tolling contract for a gas-fired generation project, and provides the offtaker (typically a utility) with capacity, energy and other products generated by a grid-connected, stand-alone battery project. As the “seller” under the agreement, the project sponsor is responsible for developing, owning, operating and maintaining the battery project, and retains technical operational control of the battery. As the “buyer” under the Agreement, the offtaker typically exercises full authority to charge and discharge the battery, subject to the battery’s operating limitations and other agreed dispatch parameters. In addition, the offtaker typically pays for and delivers all charging energy from the grid to the battery, and acts as “scheduling coordinator” or “market participant” for the battery in managing its scheduling arrangements. The offtaker pays the project sponsor a fixed (usually monthly) capacity charge for its right to utilize the battery’s capacity, and frequently a variable operating or “energy” charge for dispatches instructed by the offtaker. The capacity charge may be subject to reduction for decreases in capacity, availability or efficiency of the project.

2 CAPACITY SALES AGREEMENT

The capacity sales agreement is a variant of the energy storage tolling agreement, and has been used in jurisdictions such as California, where utilities seek to contract for resource adequacy benefits or other capacity attributes required to be procured by the utilities. Three principal differences exist between a capacity sales agreement and an energy storage tolling agreement. First, under a capacity sales agreement, only the capacity and capacity attributes of the battery storage project are sold to the

offtaker. The project sponsor is entitled to sell all of the battery’s other products, including energy, ancillary services, etc., to third parties or on a merchant basis. Second, the offtaker pays the project sponsor a monthly capacity charge, but no variable or energy charge. Finally, the project sponsor retains not only technical operational control of the battery, but also full authority over charging and discharging. The project sponsor and offtaker may agree to certain exceptions to these arrangements, for example the offtaker’s right to dispatch the battery during a limited number of peak hours during each calendar year.

3 HYBRID POWER PURCHASE AGREEMENTS

Hybrid PPAs contemplate the sale of bundled products from a generation facility integrated with a battery storage project. Hybrid PPAs were initially expected by many in the renewables industry to become the predominant vehicle for battery storage deployment in the United States, primarily due to the federal investment tax credit that may be available to battery storage projects integrated with solar or certain other renewables facilities (described more on page 16). Although hybrid PPAs have been deployed for a number of years in islanded areas, such as Puerto Rico, to help utilities smooth intermittent renewables production flows for grid stability purposes, they only recently have become more common in the mainland U.S. During just this past year, a number of utilities in the western U.S. have executed PPAs for hybrid solar/storage projects and numerous RFOs for such projects are currently pending.

One form of hybrid renewables PPA is structured like a standard as-available take-or-pay PPA for a renewables generating project, and has been used in islanded areas where the offtaker is primarily interested in stabilizing

intermittent renewable energy flows. This type of PPA requires the project sponsor to install a battery system which is typically charged only by the on-site renewable generation project, and is then discharged to moderate renewable intermittent energy flows to the grid. The project sponsor sells as-available energy bundled with any other available products (capacity attributes, renewable energy credits, etc.) to the offtaker, and receives a fixed or escalating price in return, typically per MWh. The hybrid project must satisfy minimum levels of operating and technical requirements assessed based on the battery’s performance in smoothing out energy flows. The project sponsor, not the offtaker, typically has full discretion to charge and discharge the battery, subject to operating parameters set forth in the PPA.

Another form of hybrid renewables PPA authorizes the offtaker to decide when to charge and discharge the battery system, and also whether to charge the system from the on-site renewable generation or from the grid. This structure is utilized by offtakers seeking to exercise more control over the project, and is increasingly popular with utilities and other load-serving entities in the western U.S. Where any battery charging is from the grid, there may be a reduction in investment tax credits that may otherwise be available (see further tax detail on page 16). Variability exists in compensation structures in hybrid renewables PPAs, but typically the sponsor receives either (i) an energy charge (\$/MWh) for energy delivered plus a capacity payment in relation to the battery system (\$/kW-month) or (ii) just an energy charge (\$/MWh), but with an agreed “adder” per MWh to compensate the project sponsor for the battery system.

Key Issues in Front-of-Meter Contracts

Offtake revenue contracts for front-of-meter battery storage projects contain a variety of commercial and legal issues. These issues include “standard” issues usually found in tolling agreements and PPAs, including completion/schedule guarantee issues, curtailment, performance guarantees, defaults, limitations on liability, etc. We have described here three other issues which are unique for offtake revenue contracts for front-of-meter battery storage projects.

Compensation Structures

One set of issues arising frequently in front-of-meter contracts is the flexibility, fairness and accuracy of the compensation and payment formulas. Some front-of-meter contracts clearly allocate all current and future products and services from the battery to the offtaker, while others are not entirely clear on how future products and services will be compensated, if at all. In our experience, many utility contract forms do not address the possibility that the battery system may provide new “products” and generate future value streams not contemplated as of the execution date, and are unclear on both the sponsor’s ability to sell to those products and the offtaker’s obligation to accept or pay for them. To the extent economic viability of a project may depend on additional revenue streams, the contract should clearly address these issues.

In addition, details within compensation formulas of many “form” battery storage project contracts used in the market are often unclear or fail to contain necessary detail. This is most common in battery system fixed capacity charge formulas and project availability calculations and formulas. Among other issues, these forms frequently fail to ensure that the project is considered “available” during periods including force majeure events, grid curtailments and other similar circumstances. Similarly, certain contracts may premise capacity payments on the availability of both current and future capacity attributes, including those which are not yet available in the market. Because these formulas may assign different weights or values to different capacity attributes, it is critical for project sponsors to ensure that the formulas accurately and fairly value each type of current and future capacity attribute, allow any necessary flexibility to the

project sponsor, and also account for any relevant change in law risks.

Compensation provisions and formulas must also be consistent with the metering arrangements for a hybrid project. Depending on whether a hybrid project uses an AC- or DC-coupled battery system, the parties will need to determine at which point(s) to measure the MWhs generated, stored and/or discharged for different purposes of the PPA. Because efficiency and other losses due to the battery’s operation could reduce the amount of MWhs ultimately delivered to the offtaker, the PPA must also be clear on which party is assuming the risk for those losses, the amount of which will vary depending on the amount and manner of use of the battery system. As a separate matter, if the co-located generation project is a solar or wind facility and the project’s economics are dependent on receipt of the federal investment tax credit for the battery, the project sponsor will need to ensure that the hybrid PPA contains relevant restrictions on the offtaker’s utilization of the battery so as not to jeopardize the battery storage project’s receipt of tax benefits. See page 16 for additional details on the applicability of tax benefits to hybrid projects.

Change in Law

The rules and protocols relating to the definition and compensation of energy storage products and related interconnection arrangements are not yet settled in several markets (see pages 8 and 14 for related details). Change in law risk is therefore one of the most sensitive and highly negotiated issues in offtake revenue contracts for battery storage projects.

Certain products, like capacity-based products (e.g., Resource Adequacy in certain jurisdictions) and ancillary

services, may be contractually required to be provided by a battery storage project and are defined and ascribed value by state law or the applicable ISO/RTO tariff. A change to the legal definition or requirements could require the project sponsor to incur substantial costs to continue complying with the contract's obligations. As just one example, ISO/RTO capacity attributes rules frequently require a battery storage project to be capable of discharging continuously at its maximum capacity for a specified number of hours in order to obtain credit for resource adequacy or other state-mandated capacity attributes (e.g., four hours). Offtake contracts for front-of-meter projects often require the project sponsor to provide capacity attributes and to "take all actions" to qualify for these benefits throughout the delivery term. If a project sponsor installs a battery designed to discharge at maximum capacity for the specified number of hours, and the rules then change and increase the number of hours, the project sponsor could be required to incur significant upgrade costs to comply.

A project sponsor can adopt one of several contractual approaches to reduce change in law risk, and the most effective method depends on the project sponsor's risk tolerance and the offtaker's long term product requirements and flexibility. One option is for the project sponsor to agree to comply with certain contractual requirements up to a pre-agreed compliance expenditure cap over each contract year or over the entire delivery term. Alternatively, the project sponsor may agree to comply with all relevant obligations so long as no modifications to the battery storage project are required. Finally, a sponsor may include a set of "operating parameters" of the battery system and simply agree to

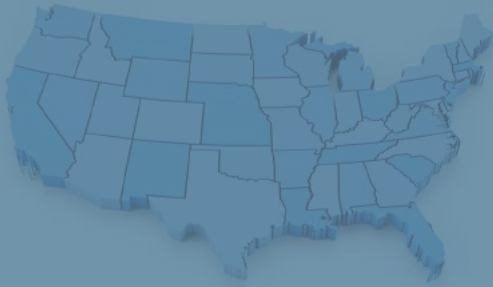
provide any and all products consistent with those parameters.

Offtaker Dispatch Authority

The scope of the offtaker's dispatch authority over the battery arises frequently as an issue in capacity sales agreements and hybrid PPAs. In capacity sales agreements, the offtaker may require dispatch authority during periods when it expects increased congestion in the battery's service location or pricing node. The parties will need to evaluate how a temporary transfer of dispatch authority impacts the project's scheduling, metering and compensation arrangements. In addition, the project sponsor may wish to limit the offtaker's dispatch rights to the extent they could reduce the battery's capacity or efficiency performance levels.

In a hybrid PPA, if the offtaker has dispatch authority over a battery system, the project sponsor will need to include relevant operating parameters and limitations on the offtaker's discretion. In addition, if the co-located generation project is eligible for federal investment tax credits, the hybrid PPA should include appropriate limitations on the offtaker's ability to charge from the grid.





Within the United States, certain states have undertaken significant efforts to incentivize and deploy battery storage projects, while others have taken few, if any, efforts. A number of states have set targets for installation of energy storage capacity, and in certain states on the west coast, utilities are now working to install storage capacity to meet them. Certain states on the east coast have also set their own targets and are in the process of developing storage incentives. The states which have made the most progress in promoting battery storage include Arizona, California, Colorado, Hawaii, Maryland, Massachusetts, Nevada, New Jersey, New York and Oregon.

ENERGY STORAGE STATE POLICY UPDATE

By Walter Alarkon and Peter Richmond

Arizona

The Arizona Corporation Commission is evaluating the addition of an energy storage procurement target of 3,000 MWs by 2030 as part of an update to the state's renewable portfolio standard. If adopted, the mandate would be the largest in the country.

which provides rebates for qualifying distribution-connected energy storage systems. The program has a \$166 million annual budget through 2020 for rebates for storage and other technologies.

California

California has led the country with the first significant mandates and incentives for energy storage. Legislation enacted in 2010 and implemented by the California Public Utilities Commission requires the state's three investor owned utilities (IOUs) to procure 1,325 MWs of energy storage capacity by 2020 with installation by the end of 2024. The IOUs are required to issue requests for offers (RFOs) for procurement of energy storage every two years through 2020 with the MW size of targeted storage procurement increasing in each round. Since 2013, the IOUs have solicited bids for projects to satisfy local capacity requirements, including, most recently, Southern California Edison's Moorpark LCR RFO for up to 164 MWs of local capacity resources. In 2016, California enacted legislation requiring deployment by the IOUs of an additional 500 MWs of behind-the-meter and distribution-connected energy storage capacity.

Colorado

In June 2018, Colorado enacted a law requiring the state's Public Utilities Commission to establish by February 2019 a process for utilities to procure energy storage. Colorado's law, however, does not set a mandate for MWs of storage capacity like California and certain other states.

Colorado's largest utility, Xcel Energy, held an RFP in 2017 for both solar-plus-storage projects and storage-only projects. A publicly available draft of the procurement results revealed 87 solar-plus-storage bids totaling 16.7 GWs of capacity and 28 standalone storage bids totaling 2.1 GWs of capacity.

In addition, California has incentivized energy storage through its self-generation incentive program (SGIP),

Hawaii

In 2017, Hawaii's Public Utilities Commission approved a power supply improvement plan submitted by the state's largest utility, Hawaiian Electric Company, which proposes deploying 220 MWs of energy storage by 2022. Procurement is already underway, as Hawaiian Electric Company has integrated storage into its 2018 renewables solicitation process.

Maryland

Maryland is providing a state tax credit for 30% of installation costs of storage projects installed between January 1, 2018 and the end of 2022. The Maryland Energy Administration will award a total of \$750,000 in tax credits, with each credit being capped at \$75,000 for commercial storage projects and at \$5,000 for residential storage projects.

Massachusetts

In 2017, Massachusetts set a non-binding target to deploy 200 MWhs of storage by January 1, 2020. To increase efforts at achieving this target, each electric utility in Massachusetts is required to submit a report to the Department of Energy Resources (DOER) by January 1, 2020 detailing how it has complied with the energy storage target.

In 2017, Massachusetts awarded grants of up to \$1.25 million each to 26 pilot projects (totaling nearly \$20 million) that demonstrate storage implementation and deployment of storage technologies.

In 2018, Massachusetts will also begin issuing payments to solar system owners under the Solar Massachusetts Renewable Target (SMART) program, with bonus payments for systems no larger than 25 KW that integrate battery storage. Under SMART, a homeowner that has installed a solar system with a

capacity of 25 KW or less will receive compensation at a per-KWh rate for the energy produced; the rate is increased if storage is installed and used with the system.

Nevada

In 2017, Nevada enacted legislation directing the Public Utilities Commission of Nevada (PUCN) to complete a study of the costs and benefits of energy storage by October 1, 2018. If the study demonstrates that energy storage is in the public interest, then the PUCN will establish biennial energy storage procurement targets for electric utilities.

Separate legislation in 2017 provides incentives of up to \$1 million per year between 2018 and 2023 for the adoption of energy storage benefiting low-income rate payers.

New Jersey

In April 2018, New Jersey enacted legislation calling on the Board of Public Utilities (BPU) to establish a process and mechanism to achieve a target of 600 MWs of energy storage by 2021 and 2 GWs of energy storage by 2030. The BPU must issue a report by April 2019 regarding energy storage needs and opportunities in New Jersey. Within six months of completion of the report, the BPU must initiate a proceeding to establish the process and mechanism to achieve the energy storage targets.

New York

In 2017, New York enacted legislation requiring that the New York Public Service Commission (PSC) establish in 2018 a target for energy storage deployment through 2030 and implement programs to enable achievement of those targets. The PSC has also issued an order for each utility in New York to deploy energy storage projects at two or more distribution substations or feeders.

Gov. Andrew Cuomo has called for a target of 1.5 GWs of energy storage capacity in the state by 2025, along with at least \$200 million from the NY Green Bank for storage-related investments and at least \$60 million for pilot programs to promote projects and other storage efforts, such as new policies that would support financing and streamline permitting, customer acquisition and interconnection rules. The PSC has already approved measures aimed at meeting Gov. Cuomo's goal, including authorization for Consolidated Edison Company to expand use of battery storage systems, and is expected to issue a 2030 storage target that meets or exceeds Gov. Cuomo's proposal.

Oregon

In 2015, Oregon enacted legislation that requires its two largest utilities to each procure a minimum of 5 MWhs of energy storage by January 2020.

Key Contract Structures and Issues

Behind-the-Meter Structures

Offtake revenue contracts for behind-the-meter battery storage projects include transactions for the sale of products and services provided by a battery system to a utility (utility services agreements, including demand response contracts), transactions for products and services provided by a battery system to a commercial or industrial (C&I) host customer on whose site the battery is installed, as well as transactions combining both features.

Small behind-the-meter battery storage projects, when aggregated across C&I sites, have the capability of providing a wide range of products and services to utilities, including capacity attributes, peak management and load shifting abilities (such as demand response services), ancillary services, and grid support functions. They can also, simultaneously, provide value to the host customers, including energy arbitrage (or time-of-use cost management), demand charge reduction and back-up power supply.

1 UTILITY SERVICES AGREEMENTS

Under a utility services agreement, the battery storage project provides one or more products or services to the utility, often including capacity attributes and demand response services. The project sponsor at its own cost installs and aggregates several small, distributed battery storage projects at different C&I sites in a specified geographic area, with each project serving the load of its respective host customer. The sponsor agrees to make the fleet of batteries available for dispatch by the utility, subject to the batteries' operating limitations and other agreed parameters. The utility typically retains first priority over the use of the batteries, although in certain cases the sponsor or the host customer may utilize the batteries when they are not being used by the utility. The payment arrangements are similar to those under the energy storage tolling arrangement described above, however the variable payment may be based on the actual reduction in each host customer's usage of electricity from the grid upon dispatch by the utility, instead of the amount of energy discharged by the battery.

2 HOST CUSTOMER AGREEMENTS

Host customer agreements are frequently similar in structure to distributed, behind-the-meter solar power purchase agreements used for on-site solar projects: The host customer or landlord provides certain premises at the host site to the project sponsor who installs the battery system at the site at its own expense. The battery typically charges from the grid and discharges to provide services to the customer. The most common services include time-shifting, demand/peak charge management and energy back-up. If the project is also linked to a utility services agreement, then the utility will have rights to direct battery dispatches for demand response services to satisfy the host customer's load. Where high demand charges are in effect for C&I customers (in states such as California and New York), time-shifting strategies can reduce a host customer's demand charges. In some cases, a project sponsor may guarantee a certain level of cost savings through demand charge reduction, and the host customer may pay the project sponsor a certain percentage of any resulting savings.



Key Issues in Behind-the-Meter Contracts

Utility services agreements contain several of the same issues found in utility offtake contracts such as tolling agreements and PPAs, and host customer agreements include the same issues ordinarily found in distributed solar PPAs. Below we identify a few other issues which are unique to offtake revenue contracts for behind-the-meter battery storage projects.

A central issue for project sponsors is satisfying the utility and host customer's agreed usage priorities while ensuring that the project sponsor maintains access to all current and future value streams of the project. Under a utility services agreement, the utility's desire for highest priority over the battery may conflict with the project sponsor's desire to access additional, future revenue streams to increase the financeability of the project. Several similar coordination issues arise in the context of host customer agreements, including prioritization of dispatch authority between the host customer and the utility, incorporation of flow down provisions from the utility services agreement, and coordination of the terms and conditions of host customer agreements among one another.

The scope of project sponsor defaults and utility termination rights are critical to address in these agreements. In light of the relatively high capital cost of installing battery storage projects and the uncertainty in several markets regarding the existence of compensation sources for merchant

storage products, project sponsors can be substantially exposed in the event of a terminated utility services agreement. Because the utility is buying a "custom" product – for instance, demand response services from the aggregation of distributed C&I battery storage projects – a failure of the utility services contract could result in a portfolio of uncontracted battery storage projects and an unrecoverable loss to the project sponsor. Based on recent regulatory developments described on page 14, some of these risks may decrease in the coming years.

Other change in law risks are particular to host customer agreements. If a host customer agreement provides for payments to the project sponsor based on the reduction of demand charges, any change in tariffs that reduce demand charges could jeopardize the agreement. A better approach (for a project sponsor) is to peg compensation to reduction in demand (tied to a baseline), rather than a demand charge. In addition, project sponsors may wish to address its remedies expressly in the event a change or elimination of financial incentives and rebates (such as SGIP in California) reduces the financial viability of small, behind-the-meter battery storage projects.

EPC/INSTALLATION TESTS AND LONG-TERM PERFORMANCE GUARANTEES

Introduction

A critical component for any project development and financing involving a new technology is a properly structured EPC or installation contract, including appropriate acceptance and performance tests for the entire system, as well as individual component testing for key system components. For battery systems, these EPC or installation provisions typically must be combined with long-term performance guarantees, provided either by the EPC contractor or a major equipment vendor, such as the battery manufacturer. Both the EPC/installation provisions and long-term performance guarantees must usually be provided by a creditworthy entity or backed by credit support, or both.

Set forth here is a brief description of the key EPC/installation 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. In our experience, there are not yet clear market or industry standards for each of these guarantees and tests, or for the contractual remedies attached to shortfalls in each, and great care must be taken to ensure consistency and maximum flow-through between performance guarantees in battery system utility offtake contracts, on the one hand, and the EPC, equipment supply and O&M contracts, on the other.

Specific Tests and Guarantees

1. Capacity. In order to confirm the capacity (in MWs) of a battery storage system, or the average power and energy that can be discharged by a battery project, an EPC contractor or vendor will typically be required to conduct a capacity test. A capacity test is perhaps the most fundamental of the battery system performance tests. One way to conduct such a 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 EPC or other contract compliance. If compliance is not satisfied, then one or more different vendor/contractor obligations may be triggered, including potentially liquidated damages or the obligation to repair, replace or augment the battery system. The provisions of some contracts fail to distinguish between “instantaneous” capacity (measured in MWs) and “durational” or “sustained” capacity (measured in MWhs), each of which is a critical but distinct concept that must be addressed in the relevant contracts. Additionally, capacity guarantees and tests will typically be required not only as a condition to acceptance of a project, but also as a continuing guarantee, the latter either through some form of continuing multiple-year performance guarantee

or via a long-term service agreement (LTSA), capacity maintenance guarantee or agreement or other contractual structure.

2. Charge and Discharge Rates. A contractor or vendor will frequently be required to conduct a charge rate or charge time test, in order to confirm the time (in minutes or hours) required to charge the system from its minimum to maximum states of charge. Although testing details may vary, the contractor or vendor 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 or vendor may be required to conduct a discharge rate test.

3. Availability Testing. In order to ensure that a battery system is suitable for commercial operation, a contractor or vendor 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 and to select 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 determining 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 continuing or long-term battery system contract.

4. Efficiency Testing. A battery system will typically be tested for its efficiency, meaning the system's ability to discharge out of the system all of the quantity of energy (in KWhs or MWhs) that have been delivered or charged into the system. Given the potential loss of energy of battery systems through heat discharge or use of energy for auxiliary load, an efficiency test is integral to an overall testing program. Although efficiency test details vary, one simple approach is to measure the amount of energy (in KWhs or MWhs) charged into a system required to take the system from its minimum to maximum states of charge, and then measuring the amount of energy discharged through the system's meter (in KWhs or MWhs) to take the system back to its minimum state of charge. By comparing the quantity of energy held 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. Auxiliary Load Testing. Like other energy projects, a large battery storage project may require use of stored energy to power the internal systems of the battery project. As such, it is not uncommon on larger projects to perform tests to determine the load consumed by the project itself. Such testing will be performed and evaluated in conjunction with the project's efficiency testing described above.

6. Ramp Rate Testing. In order to determine the ability of the project to ramp the battery storage project's power input or output between different set points, a contractor or vendor will frequently be required to conduct a test to determine the response time of the project to changes between power output levels for charging or discharging. This type of test may be particularly important to evaluate a system's ability to provide ancillary grid services. In such a test various set points and an equal number of ending set points (selected by the owner, or pre-agreed) are used for testing. The parties will measure the time required to ramp power output between each starting and ending set point. Although details vary, the change in power output may be divided by the time period required to make each change in power output to determine the ramp rate for each change in set point and the average ramp rate.

7. Response Time Testing. A response time test is frequently used in order to determine the ability of a project to respond to commands from an off-line state, and determine response time to go from an off-line state to the

maximum discharge rate and from an off-line state to the maximum charge rate.

9. Noise Testing. If applicable, it may be necessary to determine whether a project complies with local or other applicable noise ordinances or requirements. When conducted, it will be important to confirm that acceptable noise levels are satisfied in different project operating modes or set points.

10. Subsystem Testing. Depending on the specifics of each project, it may be important to test a battery storage system's subsystems, including potentially project's HVAC, lighting, station/backup batteries, etc.

ENERGY STORAGE REGULATORY UPDATE

By Adam Wenner

FERC Order No. 841 Mandates that RTOs Facilitate Participation by Wholesale Storage Projects

FERC's landmark Order No. 841, issued in February 2018, requires FERC-regulated regional transmission organizations – namely PJM, NYISO, ISO-New England, MISO, SPP and CAISO – to revise their tariffs and market rules to accommodate the “physical and operational” characteristics of storage projects. FERC defines an “energy storage resource” as a resource capable of receiving electric energy from the grid and storing it for later injection back to the grid.

FERC's storage policies accordingly apply to all types of storage resources. These RTOs must file by December 2018, and implement by December 2019, energy storage “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 kilowatts.

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. 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. Order No. 841 does not apply to utilities that do not participate in RTOs – primarily utilities in the southeastern U.S. and in the Pacific Northwest, and does not apply in ERCOT.

FERC Rules that Interconnection Agreements Must Accommodate Stand-Alone and Hybrid Storage/ Renewables

FERC Order No. 845, issued in April 2018, confirmed that storage projects are “generation facilities” that are able to use FERC's pro forma interconnection agreement. Order No. 845 also permits generators with GLIAs or their affiliates to use “surplus” capacity rights in their existing interconnection agreements for storage projects that they or their affiliate adds to existing generation. However, simultaneous output by the generator and the storage facility may not exceed the capacity specified in the interconnection agreement at any time.

Storage Facilities Can Qualify for PURPA Pricing and Regulatory Exemptions

Storage projects that provide power to utilities or RTO markets and that are located in the continental U.S., other than in the ERCOT region of Texas, are regulated as “public utilities” under the Federal Power Act. Under the Public Utility Regulatory Policies Act of 1978 (PURPA), “qualifying” small power production facilities 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. FERC has ruled that storage projects that are charged by renewable energy can self-certify as “qualifying facilities” (QFs) under PURPA, as long as at least 75% of the charging energy is from renewables. QF status also exempts the project from FERC and state utility regulation. In non-RTO markets, QF status can ensure that a project has a market for its power and can provide more favorable PURPA rates.

California PUC Adopts Ruse 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, in Rulemaking 15-03-011 issued in January 2018, the California Public Utilities Commission 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 to a “higher” 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 to the CPUC their 2018 Energy Storage Procurement and Investment Plans that implement these requirements for multiple-use storage projects, and the CPUC is currently reviewing those submissions.

Storage as Transmission

In addition to providing energy market services, storage projects can perform transmission functions. FERC’s 2017 Storage Policy Statement permits storage projects to provide both cost-of-service regulated transmission and competitively-priced market services, but revenue from market services must be credited against the cost of service. The “storage as transmission” issue is most active in CAISO, which is now conducting a proceeding to examine “Storage as a Transmission Asset,” and is considering innovative approaches to classification and revenue issues. In addition, in FERC Docket No. EL18-131-000, The Nevada Hydro Company, Inc., the developer of a proposed \$2 billion pumped-storage project in California has sought a FERC order finding that its project should be classified as a transmission facility, and, if selected by the CAISO in its transmission plan, should recover its cost-based rate recovery through the CAISO transmission access charge, rather than having to bid into CAISO’s energy markets. The case is now pending before FERC.

In Texas, the question of whether storage projects can be classified as transmission is under review. In Texas Public Utility Docket No. 46368, a distribution utility, American Electric Power Texas, sought to install a one MW lithium-ion battery at a cost of \$1.6 million, rather than adding transmission upgrades at a cost of \$6-17 million. Texas’s Public Utility Regulatory Act prohibits distribution utilities from owning generation; AEP proposed to classify the battery as a distribution asset, which would mean that the battery’s costs would be included in AEP’s rate base, assuring its cost recovery. Accordingly, the PUCT has directed its staff to engage in a rulemaking proceeding to address the

energy storage issues raised in the AEP proceeding.

Retail Sales

While FERC regulates wholesale power sales in the continental U.S., state commissions regulated “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 is 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.

ENERGY STORAGE TAX UPDATE – FREQUENTLY ASKED QUESTIONS

by Wolf Pohl

Do storage systems qualify for federal income tax credits?

No federal tax credit currently exists for standalone battery energy storage systems. However, a storage system can qualify for the federal investment tax credit (ITC) if it is considered to be a component of a solar project (or certain other renewable energy project) that itself qualifies for ITC, subject to the following details:

Solar. Qualifying solar projects are eligible for a 30 percent ITC if construction begins before January 1, 2020. The 30 percent ITC for solar is phased down to 26 percent for projects for which construction begins in 2020, to 22 percent for projects for which construction begins in 2021, and to 10 percent for projects for which construction begins after December 31, 2021. Additionally, to be eligible for the 30 percent, 26 percent, or 22 percent ITC, the solar project must be placed in service before January 1, 2024 (if not, the ITC is reduced to 10 percent).

Wind. For wind projects, the ITC can be claimed in lieu of the production tax credit (PTC). However, for those wind projects, the phase down of the ITC matches the phase down of the PTC: 30 percent ITC if construction began before January 1, 2017, with 20 percent, 40 percent, and 60 percent reductions to ITC if construction begins in 2017, 2018, or 2019, respectively. For such wind projects which include a storage component, the relative benefit of the ITC and PTC should be compared, but it may be that the PTC is a better option.

Other Renewable Technologies. Other renewable technologies, including fiber-optic solar, geothermal, fuel cell, microturbine, combined heat and power, and qualified small wind, and geothermal heat pumps, can qualify for the ITC, with the specific ITC

percentage, “begun construction” date and “placed in service” date requirements depending on the particular technology. The IRS guidance with respect to combined renewable generation and storage has focused on solar and wind projects, however, the rules described below with respect to solar-plus-storage projects might arguably apply to these other technologies as well.

Cliff Test

The regulations provide for a 75 percent “cliff test” -- no more than 25 percent of the energy used to charge the storage system can be generated by non-solar sources, otherwise the storage system does not qualify for the ITC. For this purpose, the storage system’s energy inputs are measured annually over one-year periods beginning with the storage system’s placed-in-service date. If less than 100 percent of the energy used to charge the storage system is generated by solar sources in any such individual year, the ITC-eligible cost of the storage system is reduced proportionately (e.g., if 90 percent of the energy used to charge the storage system comes from solar sources, then 90 percent of the storage system’s cost is ITC-eligible). However, if the 75 percent “cliff test” is not satisfied, then no portion of the storage system’s cost is eligible for the ITC. For hybrid solar projects involving storage systems which are not charged entirely from the solar project, the developer will need to closely monitor compliance with the 75 percent “cliff test” in order to ensure that the storage system will qualify for the ITC and that the ITC for the storage system will not be recaptured.

When does the storage system need to be placed in service, as compared to the date the solar project is placed in service, in order to be ITC-eligible?

The IRS rules do not expressly require that the storage system be placed in service at the same time the renewable system is placed in service in order for the storage system to benefit from the ITC. Although there is no clear guidance from the IRS on this issue, two private letter rulings support the conclusion that later-added storage systems qualify for the ITC. In

one private letter ruling, the IRS ruled that a storage system added to an existing wind farm qualified for ITC and in another private letter ruling, the IRS ruled that a storage system added to a residential solar system qualified for the residential energy credit. However, even in light of these private letter rulings, some investors may be hesitant to fund later-added storage projects on the grounds that there is not yet enough clear guidance on this question.

Can the taxpayer that owns the storage system be a different taxpayer from the owner of the solar project?

The IRS rules do not require the owner of the storage system and the owner of the solar project to be the same taxpayer. However, there is no guidance explicitly allowing for different owners, so currently there is no clear resolution on this issue. In both of the private letter rulings involving later-added storage mentioned above, the same taxpayer owned the storage system and the solar project. Absent further guidance, investors are likely to require that the same taxpayer own both the storage system and the solar project.

Where is the storage system required to be physically located in order to be ITC-eligible?

As with the ownership question above, the rules do not require the storage system to be located in physical proximity to the solar project to qualify for the ITC. However, the IRS has not provided clear guidance allowing for the storage system to be located at a site physically remote from the solar project. In two private letter rulings addressing storage systems qualifying for the ITC, the IRS mentioned that the storage system was on the low-voltage side of the project. For purposes of determining what portions of a solar project are eligible for the ITC, the IRS generally defines the boundary of the portion eligible for the ITC as the point where voltage is stepped up for transmission. In light of these considerations, and absent further guidance, investors are likely to require that the storage system be located physically proximate to (and on the low-voltage side of) the solar project.

ENERGY STORAGE UPDATE – UNITED KINGDOM

by Lis Blunsdon

Battery storage has not yet achieved the same levels of deployment in the United Kingdom (UK) as it has in the United States. In the last three years, several research projects and commercial trials in the UK have successfully demonstrated the potential for growth in the sector. One critical issue that was identified during these trials and demonstration projects was the need for regulatory certainty as to where storage should fit in the existing UK electricity licensing regime. The ramifications of that decision would determine not only what type of administrative and regulatory criteria would need to be satisfied when developing storage projects in the UK, but also who could own the assets; under European Union legislation, strict unbundling rules prohibit any entity owning a distribution or transmission asset from also owning a supply or generation asset.

In the autumn of 2017, the UK's energy regulator, Ofgem, published a consultation document setting out a proposal whereby storage in the UK would be licensed as a subset of electricity generation, and proposing changes to existing distribution licenses which would prohibit licensed distribution network operators (DNOs) from owning and operating storage assets other than in specific and limited circumstances where to do so would help to ensure the safe and reliable operation of a network, within the normal business activities of a DNO. Although the merits of whether or not battery storage should be classified as a generating asset or not are outside the scope of this article (suffice it to say that there are many reasons why a separate asset class might have been preferable), the main issue preventing further deployment of battery storage in the UK is the absence of primary legislation required to create the necessary license conditions and exemptions. This means that an amendment to the

Electricity Act is required and there is simply no parliamentary time available due to the ongoing process of Brexit. The head of the government department responsible for Smart Energy (of which storage is a part) was quoted recently as stating that it could be early into the next decade before the necessary changes are made.

On the other hand, progress on updating the distribution license conditions has been made, as these can be amended without the need for primary legislation. A final response on the proposed license changes is currently awaited. Ofgem has also published guidance on the treatment of co-located storage assets at sites which are in receipt of subsidies under the Renewables Obligation Scheme, making it clear that renewables subsidies can be claimed on power which is used to charge storage assets. This is a helpful development and clarifies an area which had previously caused uncertainty.

As is the case in many other jurisdictions, one of the main requirements for a successful storage project in the UK is to secure reliable, long term revenue streams, or to "value stack." Ancillary services, the capacity market and flexible power purchase agreements all play their part in ensuring optimal revenue streams. In the UK, National Grid operates the UK's high voltage transmission system and is responsible for the procurement of ancillary services across that network. The UK capacity market provides payments for generators that are able to generate during system stress events, and power purchase agreements are procured bi-laterally between market participants. Capacity market contracts are procured through an auction process. The process is technology neutral, and while the technical requirements have proved challenging to storage projects, each round of auctions has resulted in new build storage projects winning 15 year contracts.

With respect to storage and ancillary services in the UK, in the summer of 2016, National Grid issued a tender for approximately 200 MWs of Enhanced Frequency Response, a particular type of fast frequency response. Eight

projects, all of which were battery storage projects, secured contracts totaling 201 MWs of capacity. Not long thereafter, National Grid launched a major consultation on the reform of the ancillary services market, which is still ongoing, but which will hopefully result in a more transparent, accessible suite of standardized ancillary services products. This should be beneficial to the storage industry as it should become easier to obtain contracts, and possible to enter into multiple contracts that provide different services at different times — one of the key distinguishing advantages of battery storage as a technology. The PPA market in the UK remains challenging for all technologies in the UK market, and, in line with the trends being seen in the ancillary services markets, flexibility is becoming more valuable as generators see the value of their income from energy markets decrease. This is reflected in the current debate around PPA structures in the UK, be they utility or corporate, and will drive the development of new forms of contract over the coming years.

Battery storage at any scale is currently a challenge in the UK, but despite the lack of a definitive license regime, the market is gradually developing and finding its way to solutions. Behind-the-meter schemes, which by their nature tend to involve smaller units which are more likely to be license exempt, are increasing, with several firms announcing market initiatives recently — see for example the joint venture between Thrive Energy and Aura Power which will provide batteries to business users at no cost to the customer. The battery will be managed for the mutual benefit of both parties, with income from ancillary services playing a significant role in the model. Larger, grid connected storage projects are also increasing in number, with UK Power Reserve recently announcing a partnership with Fluence to install the first phase of the 120 MWs of battery storage for which it has capacity market contracts.

SOLAR + STORAGE PPA CHECKLIST

by Les Sherman

Recently there has been enormous growth in the number of utility RFOs and other solicitations for new PPAs that combine solar + battery storage. Many solicitations either have not provided forms of the PPA, or do not adequately address all relevant issues. Set forth below is a useful checklist that can be used for planning a PPA that combines solar plus battery storage products. With minor changes, the checklist also can be used for planning wind (or other renewables generation) plus storage PPAs. For ease of reference, we refer to a renewables + battery storage PPA as a "Hybrid PPA".

A BACKGROUND ASSUMPTIONS/ CONFIRMATIONS

Before starting the Hybrid PPA drafting or structuring, it is helpful to confirm the following background facts and assumptions, much of which will instruct Hybrid PPA drafting

1. Solar Generating Capacity proposed (typically in MWs AC)
2. Battery Storage Capacity proposed (typically in MWs AC for an agreed duration (e.g., 4 hours))
3. Term: base term plus extensions
4. Pricing: Confirm whether storage product pricing is an "adder" to the renewable energy MWh price, a monthly capacity based price (\$/kW), or other
5. Storage Product: What specific "products" will the battery storage provide, or stated differently, how and for how long and at whose direction will the storage be charged and discharged from time to time, details of which are more fully discussed below
6. Review facts to confirm an "integrated" facility for ITC Tax issues, including ownership, timing of construction of pv and storage, charging, etc.

B PROJECT PHYSICAL CONFIGURATION

Metering and delivery issues are far more complicated in Hybrid PPAs than simple renewables PPAs, and may vary significantly depending on whether the project incorporates AC or DC coupled battery technology. Confirm the details (using a diagram) of the project's overall physical configuration, including at a minimum the following:

1. Solar modules and other key generation components
2. Battery storage key components
3. Connection lines
4. Inverters
5. Transformers
6. Meters
7. Delivery/Interconnection Points
8. AC or DC coupled storage

C BATTERY CHARGING DETAILS

Assuming there will be primarily charging from the solar generation, and potentially some from the grid, confirm following details:

1. Overall management of charging decisions (timing, quantities, source, etc.)
2. Communications/management protocols
3. If any grid charging:
 - a. Scheduling Coordinator role
 - b. Delivery details and points
 - c. Financial Responsibility / Payments
 - d. PPA contractual limitations to comply with ITC 75% cliff
 - e. Metering Details
 - f. Other details
4. Solar sourced charging issues
 - a. Per above, confirm management, timing, quantities, etc.
 - b. Confirm metering configuration
 - c. Other details
5. Charging Operational Parameters
6. Any other key details

D BATTERY DISCHARGING DETAILS

Confirm details, including:

1. As per above, what "Products" are being provided by the storage, or stated differently, confirm all "uses" of the battery storage
2. The portion (if any) of discharging energy that will be manually "directed" by dispatch
3. The portion (if any) of discharging that will be automatic or "programmed" in advance, as for shaping or firming
4. The relative roles of Seller and Buyer in managing discharging/dispatches
5. Communications/management Protocols
6. Scheduling Coordinator role (where applicable)
7. Allocation of any market revenues/costs from discharging or ancillary services
8. Any other key details

E BATTERY PERFORMANCE GUARANTEES AND OPERATING PARAMETERS

Confirm:

1. Key Operational Parameters (i.e., battery systems operating limitations)
2. Performance Guarantees / Tests to be offered:
 - a. As a condition to PPA COD
 - b. During Term of PPA

c. Potential Specific Tests/ Guarantees

- i. Availability
 - ii. Capacity
 - iii. Efficiency
 - iv. Others
3. Periodicity for measuring compliance with performance guarantees
 4. Consequences of performance guarantee shortfalls
 5. Other Details

F COMPENSATION ISSUES

Confirm:

1. Per the above, confirm pricing structure for solar and pricing for storage, whether a fixed \$/MWh (which would include a storage "adder"), or a separate monthly or other capacity and/or variable charge for storage
2. Metering for energy deliveries (directly from solar and storage) and any adjustments for battery losses, noting that battery losses may be large and result in lower deliveries to the grid
3. REC creation issues, noting that some States may only allow RECs for MWhs actually delivered to the grid (e.g., California), and others may deem RECs created "before" accounting for battery losses
4. Compensation consequences of battery performance shortfalls (noted above)
5. Imbalance Issues on both generation and storage
6. Other details

G OTHER ISSUES

1. Consider change in law issues in relation to State/ISO ancillary services rules, etc.
2. Changes in development or operating period security due to storage addition
3. Station use requirements/issues for energy storage assets
4. Energy storage components maintenance issues
5. Storage SCADA and AGC issues

ABOUT THE AUTHORS



Les Sherman leads Orrick's U.S. Renewables Practice and has worked for 35 years across all aspects of development, financing and M&A transactions involving renewables projects. He is currently working on numerous energy storage and renewables + storage projects. In 2017, Les represented the lead developer and equity investor in *IJ Global's* "North America Storage Deal of the Year."



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Adam Wenner leads Orrick's Energy Regulatory Practice. He has been active in the energy industry for more than 35 years and regularly advises on energy storage and other renewable energy projects and transactions across the U.S. Adam previously served as Deputy Assistant General Counsel at the Federal Energy Regulatory Commission. He is a frequent speaker at renewables conferences and events.

ABOUT ORRICK

Orrick is a global law firm with a strategic focus on Energy and Infrastructure, Finance, and Technology and Innovation. For more than 40 years, Orrick has been one of the most active firms globally in renewable energy, regularly advising on innovative and high-profile matters worldwide. We are proud to be one of only three law firms ranked at the highest level for U.S. renewable energy work by both *Chambers* and *Legal 500*.

In the energy storage industry, Orrick is an established leader. Our team has partnered with a variety of clients on complex and market-leading storage transactions, including the first-of-its-kind development, construction and non-recourse financing of a US\$200 million+ portfolio of battery storage projects in Los Angeles (*IJ Global's* 2017 "North American Storage Deal of the Year"); the development of a portfolio of stand-alone battery storage projects in the U.K., including all construction, long-term guarantee and vendor agreements; and the development of contracts for five unique utility-scale solar projects combined with co-located battery storage systems in the Caribbean.

Over the years, we have gained deep experience advising a range of industry participants in multiple jurisdictions on virtually every type of energy or infrastructure transaction. This experience enables us to provide clients with valuable industry insights and solutions that anticipate and mitigate risks, maximize flexibilities and seek to ensure the most fulsome protections in uncertain markets and environments. We offer an integrated and diverse team of renewable energy lawyers ranging from senior partners to junior and career associates located in key energy and financial centers worldwide.

For more information on our Firm and our Energy and Infrastructure practice, please visit us at www.orrick.com

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Infocast has recently expanded its energy portfolio with its inaugural event, Storage East, (October 16 – 17, 2018), which will explore the growing opportunities in energy storage across the Eastern Seaboard. Policymakers, market operators, utilities, and other stakeholders from the entire storage value chain will come together to provide definitive information on policies, programs, and procurement, and discuss how developers and vendors can profit in the Eastern US markets.

For more information about Infocast and Storage East, please call 818-888-4445.

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