Influence of Hybridization on the Capacity Value of PV and Battery Resources

Sean Ericson, Sam Koebrich, Sarah Awara, Anna Schleifer, Jenny Heeter, Karlynn Cory, Caitlin Murphy, and Paul Denholm

National Renewable Energy Laboratory

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-5R00-75864
March 2022

Influence of Hybridization on the Capacity Value of PV and Battery Resources

Sean Ericson, Sam Koebrich, Sarah Awara,
Anna Schleifer, Jenny Heeter, Karlynn Cory,
Caitlin Murphy, and Paul Denholm

National Renewable Energy Laboratory

Suggested Citation

Ericson, Sean, Sam Koebrich, Sarah Awara, Anna Schleifer, Jenny Heeter, Karlynn Cory, Caitlin Murphy, and Paul Denholm. 2022. *Influence of Hybridization on the Capacity Value of PV and Battery Resources*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5R00-75864. https://www.nrel.gov/docs/fy22osti/75864.pdf

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-5R00-75864
March 2022

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Solar Energy Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

NREL prints on paper that contains recycled content.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. The following NREL colleagues reviewed and improved this report: Jaquelin Cochran, Bethany Frew, and David Palchak. We are also grateful to our external reviewers for providing feedback on this work through an external peer review process, including Will Gorman from Lawrence Berkeley National Laboratory and Aaron Bloom from NextEra Analytics. Finally, we thank Mike Meshek for editing support and Madeline Geocaris for other communications support.

This work was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy—including the Solar Energy Technologies Office and Strategic Analysis—under contract number DE-AC36-08GO28308. All errors and omissions are the sole responsibility of the authors.

List of Acronyms and Abbreviations

AC	alternating current
CAISO	California Independent System Operator
DC	direct current
EIA	U.S. Energy Information Administration
ELCC	effective load carrying capability
ERCOT	Electric Reliability Corporation of Texas
FERC	Federal Energy Regulatory Commission
ISO	independent system operator
ISO-NE	ISO New England
GW	gigawatts
GW_{AC}	gigawatts-alternating current
MISO	Midwest Independent System Operator
MWh	megawatt-hours
NYISO	New York Independent System Operator
ORDC	operating reserve duration curve
PJM	the Pennsylvania, New Jersey, and Maryland Interconnection
PUC	public utilities commission
PV	photovoltaic
RAAIM	resource adequacy availability incentive mechanism
RTO	regional transmission organization
SPP	Southwest Power Pool

Executive Summary

Utility-scale systems that combine solar photovoltaic and battery (PV+battery) technologies are growing in popularity on the U.S. bulk power system. The business case for PV+battery systems depends on both their ability to reduce costs and their ability to generate value synergies associated with the provision of energy, capacity, and ancillary services. Capacity value can constitute a significant portion of the value PV+battery hybrids provide to the grid (e.g., through avoided or deferred capacity) *and* receive through revenues. Throughout this report, we define capacity value as the monetary value of a plant's contribution towards the planning reserve margin, which ultimately depends on market rules and structures.

PV+battery hybrids do not always fit into current market structures because of the interactions between the PV and battery components. Unique considerations for the capacity value of PV+battery hybrids include the disparate nature of participation models for PV and battery technologies in existing market rules and the potential influence of a shared interconnection capacity; limitations imposed by a shared inverter; limited ability to charge the battery in advance of capacity events if charging must be sourced from the coupled PV; and challenges or uncertainties associated with co-optimizing the operations of the PV and battery components.

Grid operators are currently considering how market structures can be modified to optimally determine the capacity value provided by PV+battery systems, and the rules of how they are integrated into markets are still being written. As with any resource, poorly designed rules could increase the cost of energy and reduce system reliability, while well-designed rules could allow markets to receive the full benefits hybrid systems can offer without overcompensating them for the services they provide. Well-designed rules for PV+battery systems must consider the unique aspects listed above, while leveraging the commonalities with existing resource types.

In this report, we summarize the technical capability and market rules that influence the capacity value of PV+battery systems. We further discuss the potential tradeoffs between computational complexity and accuracy for the various ways in which grid operators can credit PV+battery systems for capacity. Finally, we describe markets for capacity, survey current wholesale market rules applying to PV+battery systems, and provide a snapshot of the current regulatory landscape for PV+battery systems.

Simplified approaches for calculating capacity value may not be adequate for capturing the full value of PV+battery hybrids (and other flexible resources), particularly in a grid with significant shares of variable generation. While the transparency of simplified approaches—including "sum of parts" and capacity factor-based approximation methods for calculating hybrid system capacity values—is appealing, it may be outweighed by the drawbacks of limited accuracy and risks to maintaining resource adequacy in the most cost-effective manner. As a result, there is a general effort among grid operators to transition to probabilistic reliability-based methods.

Because of the growth in PV+battery systems and their increasing complexity—involving multiple configurations and likely increases in DC/AC ratios—it is important that research in capacity valuation methods continue, along with development of transparent algorithms and stakeholder vetted software tools. These improved tools and methods will help address not only the growing challenges associated with PV+battery hybrids, but they will also provide improved approaches for modeling complex resources such as advanced demand response.

Table of Contents

List of Figures

List of Tables

List of Text Boxes

1 Introduction

Solar photovoltaic (PV) installations on the U.S. bulk power system have increased rapidly in recent years, with 43% of electric generation capacity additions coming from PV in 2021 (Feldman, Wu, and Margolis 2021). At the same time, increased deployments of PV are leading to a decline in the marginal energy value and capacity value of new PV projects (Bolinger, Seel, and Robson 2019; Sivaram and Kann 2016). This paper focuses on the capacity value of pairing PV with battery storage, which can partially mitigate the decreasing capacity value of PV.

Battery storage represents an increasingly cost-competitive means of providing peaking capacity, and it also exhibits synergies with PV. For example, battery storage can offset the declining capacity value from PV generation, and PV generation further shortens net-load peaks, which increases storage capacity value (P. Denholm et al. 2021; Frazier et al. 2021). While such benefits exist for separately sited PV and battery storage projects, combining them to form a colocated or fully integrated hybrid PV+battery system offers the potential to provide cost reductions and value synergies as well.

A colocated PV+battery system shares a single interconnection point. In this paper, a fully integrated hybrid system is defined as a colocated system which is further operated and dispatched as a single unit. A more detailed discussion of the types of PV+battery systems is provided in Section 3.

Figure 1 shows colocated PV+battery systems that are expected to enter service by 2025 and demonstrates the recent acceleration in installation of PV+battery systems.[1] Looking deeper into the interconnection queues indicates an even more dramatic interest in colocated systems in the near term (Text Box 1), with queues for the U.S. restructured markets containing more than 150 GW of requested interconnection capacity for PV+battery systems[2] (Bolinger et al. 2021).[3]

---

[1] Data presented in Figure 1 are from U.S. Energy Information Administration (EIA) Form EIA-860.

[2] This value represents the AC rating or the interconnection capacity, which is the maximum amount a plant can inject to the grid. In the case of PV+battery systems, the interconnection capacity could be less than or equal to the sum of the component PV and battery capacities. For example, the interconnection request could be equal to the PV inverter capacity (which is common in CAISO); it could be equal to the sum of separate PV and battery inverter capacities (to enable maximum output of both resources during high-stress or high-value times); or it could be smaller than the PV inverter capacity, indicating the battery will charge from the PV during peak production hours.

[3] The total capacity in interconnection queues presented in Table 1 is several times more than the EIA-860 numbers. This difference is due to (1) interconnection queues extending beyond five years and (2) only plants that are expected to come online are added to EIA-860. Because only a fraction of generators that enter the interconnection queue are eventually added, Table 1 provides an upper bound of future capacity addition.

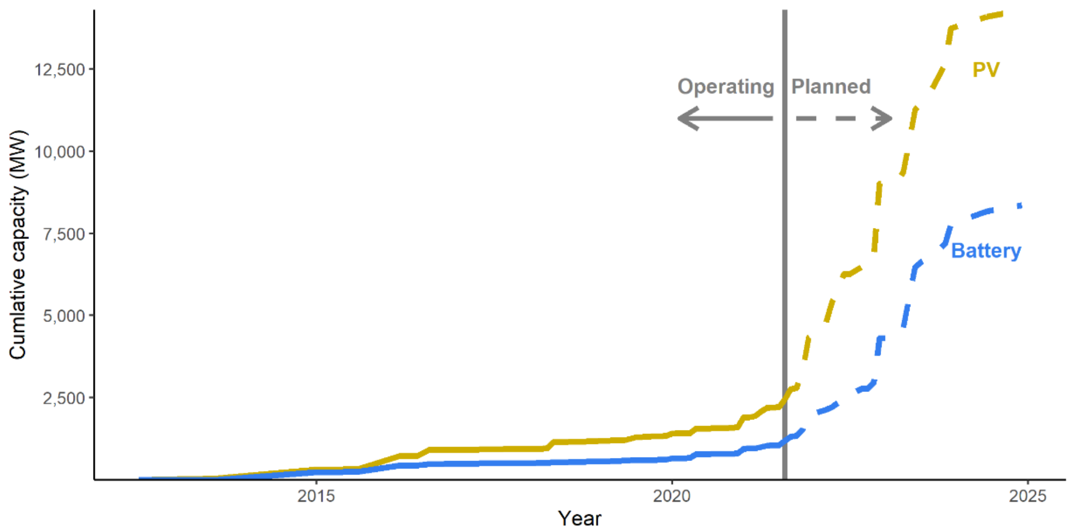

Figure 1. Operational and planned colocated PV+battery electric generation capacity from U.S. Energy Information Administration Form EIA-860M (August 2021)

Generators are included if they are expected to enter service by 2025.

Text Box 1. Queued PV, Battery, and PV+Battery Projects Across U.S. Electricity Markets

As of November 2021, U.S. electricity market queues included 144 GW_{AC} of PV+battery projects (Table 1). CAISO accounts for the largest share of capacity, but other areas—including ERCOT, MISO, and PJM—have a significant amount of queued PV+battery projects as well.

Table 1. Actively Queued Projects

RTO/ISO	Queued PV Only	Queued Battery Only	Queued PV + Battery
CAISO	4 GW	67 GW	73 GW
ERCOT	100 GW	24 GW	30 GW
ISO-NE	3 GW	5 GW	1 GW
MISO	86 GW	13 GW	13 GW
NYISO	15 GW	12 GW	1 GW
PJM	66 GW	33 GW	21GW
SPP	30 GW	10 GW	4 GW

Note: Data from market queues were accessed November 8, 2021. Values represent total requested interconnection capacity for projects with active queue status. Requested interconnection capacity is often equal to the PV inverter capacity (at least in CAISO), but it ranges from less than the PV component's capacity up to the combined PV and battery capacities. Battery capacity for colocated resources is often less than the total interconnection capacity.

CAISO	California Independent System Operator
ERCOT	Electric Reliability Corporation of Texas
ISO-NE	ISO New England
MISO	Midwest Independent System Operator
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, and Maryland Interconnection
SPP	Southwest Power Pool

The business case for PV+battery systems depends on their ability to (a) reduce costs, such as through shared hardware and interconnection costs or additional tax credits, and (b) provide additional benefits, such as through increased energy utilization from otherwise clipped energy. Another potentially important source of incremental value through hybridization—and a key outstanding question for developers, regulators, and system operators—is the extent to which PV+battery systems can provide and be compensated for capacity, which depends on the rules regarding capacity payments for PV+battery systems.

Capacity value can constitute a significant portion of the value PV+battery hybrids both provide to the grid and receive through revenues (Schleifer et al. 2022). However, the rules of how hybrid systems are integrated into markets are still being written. Market regulators are grappling with questions about how hybrid systems operate, how they may be integrated into the existing regulatory framework, and what reforms may be needed. In this report, we provide a snapshot of the current state of participation rules regarding capacity accreditation for hybrids, and we discuss the broader challenges and potential solutions to determining capacity credits for PV+battery hybrid systems. We provide an overview of capacity markets and capacity accreditation in Section 2, and we discuss specific PV+battery considerations in Section 3. In Section 4, we survey current market rules applying to PV+battery systems, and we assess the varying ways grid operators are allowing PV+battery systems to participate in capacity markets or otherwise contribute to resource adequacy requirements. Finally, we offer conclusions and recommend future research directions in Section 5.

2 Capacity Markets and Capacity Accreditation

2.1 Capacity Market Structures

The U.S. electricity sector is divided into traditionally regulated markets and restructured competitive markets (Flores-Espino et al. 2016). In traditionally regulated markets, utilities generate, transmit, and distribute electricity to end-use customers. The utility invests in assets subject to approval by its public utilities commission (PUC), typically based on the portfolio of assets that can deliver reliable electricity at the lowest cost (while meeting reliability and policy requirements). In such a setting, utilities are authorized to earn a return on investment through payments from rate payers (if the investments are deemed prudent by the region's PUC).

Traditionally regulated utilities (including vertically integrated utilities) are not as concerned about the revenue of a single asset but rather how that asset can work in concert with the rest of the system. As a result, vertically integrated utilities are likely to rely more heavily on system-level models when evaluating the potential benefits of PV+battery systems. Moreover, their investment in PV+battery systems will depend on the perspectives of the utility and the overarching PUC, including the legislation and regulations that inform their decision-making.

In restructured competitive markets, generators compete to provide electricity and ancillary services to load-serving entities. Each of the seven restructured markets in the United States (Figure 2) is organized under a regional transmission organization (RTO) or independent system operator (ISO) that sets rules regarding resource participation and market products. Figure 2 shows the magnitudes of colocated and hybrid PV+battery resources in interconnection queues, along with the total interconnection queue size, as of November 2021.

Regional resource adequacy rules are intended to ensure adequate generator capacity is available to meet anticipated system peak demand plus a threshold for error or equipment malfunction (also called a "planning reserve margin"). Resource adequacy requirements involve the RTO/ISO establishing capacity requirements for the load-serving entities within their authority. The planning reserve margin can be a fixed percent of expected peak load; for example, load-serving entities under the jurisdiction of the California PUC must procure enough capacity to meet forecasted load plus a 15% margin. Alternatively, the planning reserve margin can be based on another reliability metric; for example, several regions base their planning reserve margin on a reliability target of one day of outages every 10 years (Milligan et al. 2016). All restructured competitive market regions except ERCOT have explicit resource adequacy requirements.

Load-serving entities can meet resource adequacy requirements through bilateral contracts, utility-issued requests for proposals, power purchase agreements with specific capacity availability clauses, or direct utility investment in generators. Load-serving entities in CAISO, MISO, and SPP meet resource adequacy requirements primarily through such mechanisms (MISO 2017; CAISO 2017; SPP 2020). ERCOT also uses some voluntary bilateral contracts to ensure reliability.

An alternative is for capacity to be purchased through a centralized auction by the grid operator on behalf of all load-serving entities in the RTO/ISO. In these auctions, the market clearing price is determined by the intersection of the supply curve with a precalculated demand curve (SEIA 2018). Auctions generally take place several years out from the time period of obligation, and successive auctions are conducted to fulfill any new capacity needs that appear (PJM 2017c). ISO-NE, NYISO, and PJM each have a capacity auction. MISO also has an optional centralized capacity auction for load-serving entities to procure capacity, and CAISO has a backstop capacity procurement auction.

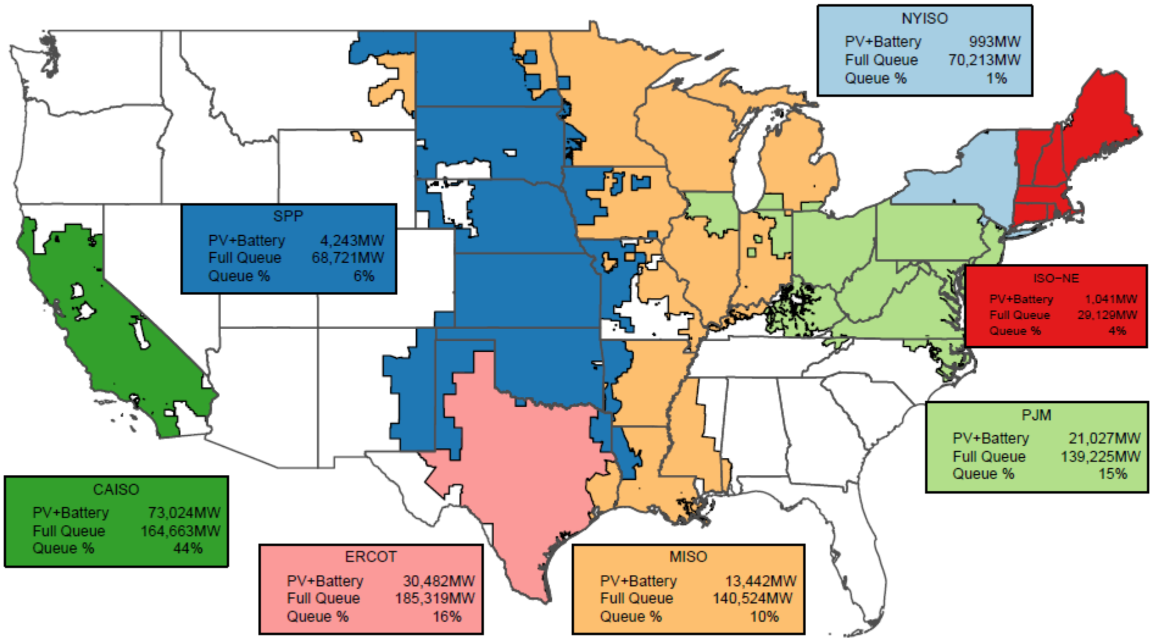

Figure 2. Colocated resources in U.S. interconnection queues as of November 2021

Queue % = [PV+Battery] / [Full Queue], where the Full Queue represents the sum of requested interconnection capacities for all types of generation and battery resources that have requested interconnection in a given market region. All MW values reflect the requested interconnection capacity, which corresponds to the AC rating.

The Texas grid operator (ERCOT) does not have explicit resource adequacy requirements; instead, ERCOT utilizes an operating reserve duration curve (ORDC), which is a mechanism that ensures electricity prices reflect the potential for shortfall conditions. In particular, the ORDC incrementally increases the electricity price ceiling—up to a maximum cap of $5,000/MWh[4]—as reserves fall below established thresholds, which are based on loss of load probability values. This mechanism relies on the economic principal of scarcity pricing—which leads to higher energy prices when reserves are scarce (EPRI 2016)—to incentivize investment in, and operation of, adequate capacity. In other words, periods of high energy prices serve as a market signal for developers to bring new generators to the market that are capable of serving load during these periods (ERCOT 2014).

2.2 Methods for Calculating Capacity Credit

Once a region has established a resource adequacy target (such as total megawatts [MW] of installed capacity), it must then calculate the ability of an individual generator to contribute towards that requirement. This process involves estimating a generator's capacity credit, or the fraction of nameplate capacity that can be relied upon during periods of high likelihood of a

[4] ERCOT's price ceiling was historically $9,000/MWh, but it was lowered to $5,000/MWh in December 2021 in response to the 2021 Winter storm.

shortfall in electricity supply (Milligan et al. 2017). This section discusses methods to calculate capacity credit and provides an overview of how those methods are applied to independent PV and battery systems. Approaches to calculating the capacity credit of PV+battery systems are discussed in Section 3.3.

Though the terms capacity credit and capacity value are often used interchangeably, we adopt the convention introduced by Mills and Wiser (2012a) to distinguish between physical capacity (capacity credit) and the monetary value of this capacity (capacity value). Means of calculating capacity credits vary by market region and by resource type; different approaches are taken to calculating capacity credit for thermal generators (Ahlstrom et al. 2019), variable resources such as wind (Milligan et al. 2017) and PV (Dent et al. 2016), and battery storage (Madaeni, Sioshansi, and Denholm 2012).

PV is often assessed based on its historical performance during high-risk or high-stress periods (Milligan 2011) (see Appendix). A battery system's nameplate capacity is based on the maximum AC output of the inverter, but its capacity credit is, in practice, often a function of its duration—where battery duration is equal to the time it can discharge at its maximum rated capacity (i.e., a 5 MW/10 MWh battery has a 2-hour duration because it can produce a full 5 MW for two hours). Most RTO/ISOs in the United States set a minimum duration requirement for a battery to receive full capacity credit, and the capacity credit is linearly derated for batteries with duration less than the minimum requirement. For example, if the minimum requirement was four hours, the 5 MW/10 MWh battery would only receive a capacity credit of 2.5 MW because that is what can be produced for the entire four-hour minimum requirement.

Such methods for calculating the capacity credit of PV and battery resources are often referred to as approximation approaches (Sun et al. 2021). Approximation approaches can provide reasonably accurate results, particularly when deployments of resources are limited (Madaeni, Sioshansi, and Denholm 2012; Mills and Rodriguez 2019). However, as deployments increase, or as interactions among additional resources increase, accuracy can fall. There are also challenges with how approximation approaches capture (a) how storage charging (or negative supply) impacts the ability of storage to provide capacity during extended-duration events and (b) the behavior of longer duration storage (Frazier et al. 2021).

Due to the limitations of approximation approaches, especially with regard to capturing interactions among resource types, there is a general effort to transition to probabilistic reliability-based methods (PJM 2021a; Schlag, Ming, and Olson 2020). Probabilistic reliability-based methods use a reliability index, such as loss of load expectation or expected unserved energy, to determine how the resource affects the reliability of the system.

Probabilistic reliability-based methods offer less transparency than the simpler approximation-based methods, but they may offer more precise measurements of a resource's contribution toward resource adequacy requirements. Probabilistic reliability-based methods can also account for several factors that are not considered in approximation-based approaches such as generator- and transmission-forced outages and the time series of generators and load (including the impact of forecast errors). The most commonly used reliability-based method to express capacity credit is the effective load carrying capability (ELCC) method (Milligan et al. 2017). ELCC is the amount by which the system's load can increase when the generator is added to the system, while maintaining the same system reliability as before the generator was added (Garver 1966).

Table 2 summarizes the resource adequacy market mechanisms and capacity credit rating methods for battery storage and PV for each market region. Rules for PV+battery hybrids are discussed in Section 4.

Table 2. Market mechanisms for supporting resource adequacy requirements and capacity accreditation methods for PV and battery technologies across market regions

RTO/ISO	Market Mechanism	Battery Accreditation Method*	PV Accreditation Method
CAISO	Load-serving entities use *requests for proposals* to meet resource adequacy requirements.	4-hour discharge capacity receives credit equal to inverter rating (P. L. Denholm and Margolis 2018).	*Effective load carrying capability (ELCC) methodology*; introduces a "flexible" resource adequacy requirement allowing seasonal variability.
ERCOT	Operating reserve demand curve (ORDC): increases electricity price ceiling as reserves become increasingly scarce; thresholds are rooted in loss of load probability values.	N/A	N/A
ISO-NE	Annually held capacity auction for resource requirements up to 3 years in advance. Annual and monthly reconfiguration auctions also held (Sun et al. 2021).	*2-hour* discharge capacity receives capacity equal to inverter rating, but adjusted depending on performance in extreme temperatures (ISO-NE 2018).	Median net output over *reliability hours*: Summer: 14:00–18:00) Winter: 18:00–19:00
MISO	Load-serving entities can meet resource adequacy requirements independently through *requests for proposals* or participate in an optional *capacity auction* (MISO 2018).	Battery storage receives a capacity credit based on 4-hour discharge capacity.	Based on historical performance during 14:00–17:00 using a 3-year *effective forced outage rate methodology.*
NYISO	*Capacity auction* for 6-month seasonal period, conducted at least 30 days before the start of the period; *monthly auctions and a spot market also exist* (Horton 2017).	Accreditation based on historical performance and duration; derates are non-linear and depend on total installed capacity. (See section 4.1.1 of the NYISO Installed Capacity Manual for details on duration derates.)	Average output over *reliability hours*: Summer: 14:00–18:00 Winter: 16:00–20:00.
PJM	*Capacity auction*. A penalty is levied for failure to meet obligations during performance assessment hours intervals, and bonuses are potentially available for over-fulfillment (PJM 2017b).	Starting in the 2023/2024 delivery year, PJM is set to transition capacity accreditation to an *ELCC methodology* (PJM 2021a).	*ELCC methodology* starting in 2023/2024 delivery year (PJM 2021a).
SPP	Resource adequacy requirements established annually for each load-serving entity; met through *self-supply or bilateral contracts* (SPP 2020).	*4-hour* discharge capacity receives credit equal to inverter rating.	SPP uses an *ELCC methodology* to calculate the capacity credits.

*Battery storage capacity credits are linearly derated for shorter duration systems.

2.3 Non-Performance Penalties

When a generator's bid is accepted in a capacity auction, it receives the market clearing price in exchange for an obligation to be available to supply energy and be dispatchable by the ISO/RTO when called upon to support grid reliability. This capacity payment is usually expressed in terms of dollars per megawatt of capacity per day (or month), and it is made regardless of when and how many times the generator is called upon. During a reliability (or capacity) event, obligated generators are called on to supply their power to the wholesale energy market at the *energy* price prevailing during the event. In most markets, resources receive payment for both generation at the energy price and the capacity value, which are provided separately (EPRI 2016).

Generators that underperform during an obligated period are liable to pay penalties to the RTO/ISO for the portion of the capacity event during which they underperformed. Historically, resources have been unable to perform due to equipment malfunctions, including situations involving extreme temperatures (PJM 2014). In most cases, such a malfunction does not prevent a generator from paying a penalty, although ISO-NE has implemented "stop-losses," or a maximum amount that will be charged for noncompliance, to prevent accruals of penalties beyond a set amount (Peralta 2017).

Table 3 describes the penalty structure imposed by various RTO/ISOs. In some markets, such as PJM, variable renewable resources are permitted to bid into capacity markets at less than their assigned capacity credit and still receive bonuses in the event of overperformance (PJM 2017a). In these instances, it may be economically viable for risk-averse resources to avoid penalties by underbidding their capacity in capacity auctions. In PJM, CAISO, and ISO-NE, penalties from generators that did not comply are distributed as bonus payments among generators that overperformed or performed without an obligation to do so (CAISO 2017; PJM 2017c; Peralta 2017).

Table 3. Description of Various Penalty Structures for Failure to Deliver Obligated Capacity

RTO/ISO	Penalties
CAISO	Must-run resources that supply less than *94.5% of their obligated capacity* available pay penalties (CAISO 2021a), which are distributed to those that provide at least 98.5% availability (CAISO 2017).
ERCOT	No penalty for failure to deliver, but generators which fail to perform during scarcity pricing periods lose out on revenues from high energy prices, based on the ORDC.
ISO-NE	A “performance payment rate” is a fixed penalty assessed on nonperforming resources. It is currently set at $5,455/MWh, and it is prorated for any period of noncompliance greater than 5 minutes. A stop-loss exists to prevent excessive penalties (Peralta 2017).
MISO	No penalty structure (Spees et al. 2017)
NYISO	Up to 1.5x *the market clearing price* in the energy spot market (Horton 2017)
PJM	A penalty is based on the modeled cost estimates for new generation for the local delivery area; penalties are distributed as a bonus across resources that overperformed first, and then to energy-only resources. A stop-loss is set seasonally (PJM 2017c).
SPP	SPP does not have specific consequences for non-performance. SPP has scarcity pricing which provides similar incentives to ERCOT, albeit with lower price caps (Parent, Hoyt, and Clark 2021).

3 PV+Battery System Considerations

The rules around capacity credits for PV+battery systems are evolving due, in part, to variations in hybrid configurations and operations. PV+battery systems can participate in markets as colocated resources or fully integrated hybrids. Furthermore, the PV and battery components can each have a separate inverter (AC-coupled), or they can share a single inverter (DC-coupled). This section discusses how unique considerations for PV+battery systems influence how they participate in markets and how they are accredited for capacity contributions.

3.1 Participation and Coupling Types

PV+battery systems are classified based on two types of projects deployed at the same location (Murphy, Schleifer, and Eurek 2021; Ahlstrom et al. 2019). First, a PV+battery system can be deployed as a **colocated resource**, in which case the technologies share a point of interconnection but operate (and bid into markets) in a largely independent fashion. Alternatively, in a fully integrated PV+battery **hybrid**, the technologies share a point of interconnection, are physically coupled, and share a control system, such that the asset operates (and bids into markets) as a single resource.

Figure 3 displays these two project types. For colocated resources, the PV and battery components are each given a unique generator ID, and they are metered (circular icons) and dispatched separately (Figure 3, left panel). Alternatively, the PV and battery technologies can operate as a single resource, receiving a single generator ID and offering a joint bid to the system operator that allows them to be dispatched together as a fully integrated hybrid based on their optimized joint operations (Figure 3, right panel) (Murphy, Schleifer, and Eurek 2021).

PV+battery systems can adopt either an AC-coupled or a DC-coupled architecture (Murphy, Schleifer, and Eurek 2021; P. L. Denholm, Margolis, and Eichman 2017). In an AC-coupled architecture, the PV and battery technologies each have separate inverters, which are connected to the same AC bus, while in a DC-coupled architecture, the PV and battery technologies share a single inverter. DC-coupled systems can be either tightly or loosely coupled, where the distinction lies in whether the battery component can be charged with energy from the grid. In particular, a "tightly DC-coupled" system utilizes a single PV inverter so the battery can charge only from the coupled PV, whereas a "loosely DC-coupled" system utilizes a bidirectional inverter so the battery can charge both from the coupled PV and the grid.

The AC-coupled architecture can be adopted for either a colocated resource or fully integrated hybrid project, depending on how the components are operated and interact with the market. A DC-coupled architecture is more likely to be operated as a fully integrated hybrid project, due to the inherent interactions that follow from the shared inverter (Gorman et al. 2020).

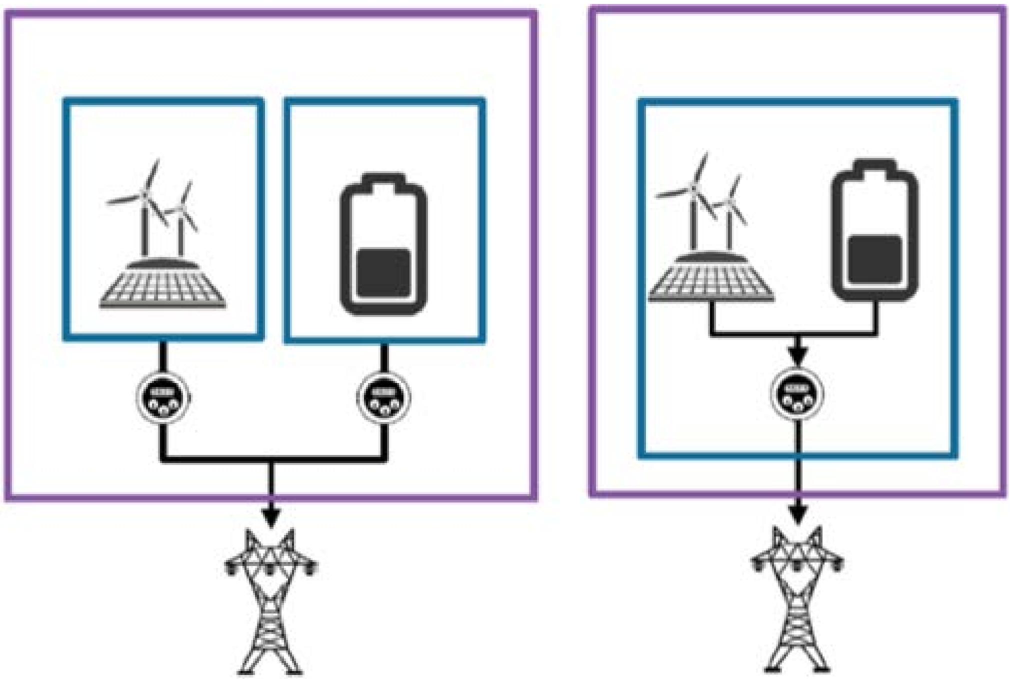

Figure 3. Example PV+battery configuration types

Purple boxes denote points of interconnection and blue boxes denote levels at which asset is dispatched by grid operator. Circles indicate a point of metering. Adapted from (Rastegar and Smith 2020).

3.2 Participation Models for Hybrid Systems

A participation model is the set of provisions that accounts for the unique physical and operational characteristics of a resource type (FERC 2018). Each resource on the bulk power system operates under a participation model that spells out the interconnection and operational rules for that resource as well as how it is compensated for the services it provides. Participation models further define which market services each resource is eligible to provide, which operational and data requirements apply to each resource, and what penalties are applied when a resource fails to meet its operational requirements.

Though specifics vary by market, each market has a separate participation model for conventional generators, variable resources (such as PV), and storage technologies (such as batteries). Examples of important differences between participation models include whether (a) storage resources are allowed to bid negative supply (to charge from the grid), (b) storage dispatch is optimized by the RTO/ISO or by the battery owner, and (c) variable resources are being dispatched based on a resource forecast and therefore not subject to uninstructed deviation penalties (Ahlstrom et al. 2019; CAISO 2021b).[5] The capacity credit of a given resource depends on its participation model as well.

Because a fully integrated PV+battery hybrid operates under a single generator ID, it will operate under a single participation model; therefore, at least one, and perhaps both, of the PV and battery components will effectively fall under a different participation model than its independent counterpart or counterparts. This shift can have important consequences for how the hybrid system is operated and the profitability of the hybrid system (FERC 2018; CAISO 2021b). As discussed in Section 4, some rules and policies may result in hybrid systems receiving higher capacity credits than similarly sized independent or colocated systems, while other rules can result in the opposite. New participation models that account for the unique attributes of PV+battery hybrids are currently being discussed and implemented, as discussed in Section 3.3.

3.3 Crediting Capacity for PV+Battery Systems

The interactions between PV and batteries must be considered when calculating capacity credits, regardless of configuration or coupling. PV resources can reduce the hours of peak net load, increasing the value of battery storage; and increased battery deployment can improve alignment between load and PV generation. Given the rapid expansion of PV generation, wind generation, and battery storage, capacity accreditation must account for high levels of both variable and limited-duration technologies.

Colocated resources can largely be represented with existing capacity accreditation methods, but *hybridization* introduces additional complexities that can meaningfully influence the joint system's capacity credit: it modifies the impacts of interconnection limits,[6] and it can introduce inverter constraints and limitations on the ability to charge the battery in anticipation of supply shortfalls. To capture these unique considerations for the capacity credit of PV+battery hybrids, market regulators are currently considering two main approaches (FERC 2021b).

The first is to assign capacity credits based on the sum of credits for each individual component. This approach, which is often referred to as the "sum of parts," simplifies the calculation and ensures hybrids are not incentivized or penalized relative to colocated or separately sited resources; however, it also runs the risk of not incorporating significant interactions between components of the hybrid resource. Interconnection and inverter constraints can be incorporated into the general sum of parts approach by placing a constraint on the system capacity credit, such that the capacity credit of the colocated PV+battery system does not exceed its inverter or interconnection limits. It is an open question whether the physical coupling of hybrid

---

[5] Uninstructed deviation is the difference between dispatch instructions and the actual performance of a resource. Uninstructed deviation penalties may consist of charges for underperformance, reduced compensation for overperformance, and removal from the dispatch process if the deviation is sufficiently large.

[6] The CAISO interconnection queue provides an example where hybridization modifies the impacts of interconnection limits: recent analysis has shown that projects commonly request interconnection ratings based on the PV inverter only (Bolinger et al. 2021). For AC-coupled projects, the combined maximum output of the PV and battery inverters exceeds the interconnection rating, the latter of which could be the defining feature for the hybrid's capacity credit.

components can be sufficiently captured under the sum of parts approach, or whether they merit a different approach to calculating capacity credits.

The second approach is to apply a capacity accreditation methodology to the combined system. This could use various methods, such as the ELCC method described in Section 2.2, in a way that captures all of the complexities listed in the previous paragraph. This approach could potentially calculate the capacity credit of a fully integrated hybrid system more accurately, by better accounting for the physical coupling of the PV and battery components (NERC 2018). At the same time, it adds another layer of complexity to the challenges of estimating the resource adequacy contributions of various resources by introducing another technology that regulators and system operators must consider in a unique fashion. Moreover, the relative size of the PV, battery, and inverter components needs to be accounted for when determining capacity credits. It may prove difficult to account for the potential variations in hybrid system component sizes given each system configuration would require its own capacity credit calculation.

The latter approach may be especially important for evaluating DC-coupled PV+battery hybrids, which have several unique considerations that AC-coupled (and separately sited PV and battery) systems do not have. For example, the shared inverter in a DC-coupled PV+battery system introduces restrictions on the charging and discharging of the battery component. For DC-coupled systems with larger battery sizes, competition for the limited inverter capacity could lead to a hybrid capacity credit that is less than those of independent and AC-coupled configurations, such that the “sum of parts” approach would be inadequate. This inadequacy may be especially important for tightly DC-coupled systems, where the battery depends on charging from the coupled PV, which may reduce the capacity credit the system receives (Mills and Rodriguez 2019). In particular, if the PV output were insufficient to fully charge the battery before the event starts, it could reduce the ability of the system to provide capacity.

4 Rules for Hybrid Resources by Region

Starting between the fall of 2019 and spring of 2020, six of the seven market regions initiated committees to develop eligibility rules for hybrid systems (Gramlich, Goggin, and Burwen 2019), and in July of 2020, the Federal Energy Regulatory Commission (FERC) held its first technical conference on hybrid resources (FERC 2020). In 2021, several of the market regions proposed updates to market rules that clarify how colocated and hybrid systems are defined, operate, and receive capacity credits; and some rule changes have been implemented. There are significant differences in approaches between market regions, and some market regions are farther along than others in developing rules for hybrid resources, meaning the business case for hybridization varies by market region. Much of the recent proposed and enacted updates are documented by FERC (2021) and subsequent filings by each market region.[7] These documents are the primary sources of information for the following discussion on specific considerations for each market region (at the time of writing). The remainder of this section is organized by market region and ordered based on the requested interconnection capacity for PV+battery projects (see Text Box 1 and Figure 2).

4.1 California Independent System Operator (CAISO)

The California Independent System Operator (CAISO) revised its tariff to include definitions and requirements for colocated and hybrid resources at the end of 2020, and it is continuing to refine its modeling of hybrid resources. Colocated and hybrid systems are quickly becoming common in California for many reasons. In addition to the relatively low marginal energy and capacity value of new PV generation, developers can add batteries to existing PV projects (proposed or operating) through the generator modification process without having to initiate a new interconnection request, as long as doing so does not require additional interconnection service capacity. This allows developers to add battery storage "more quickly and at a lower cost than establishing new and separate interconnections for the storage units" (CAISO 2021b).

Hybrid resources do not count as "eligible intermittent resources"[8] unlike the PV component of a colocated PV+battery system, which has two primary implications. First, PV+battery hybrids are potentially not exempt from non-performance penalties. Second, hybrid systems are required to provide information on battery state of charge along with meteorological and other information used to forecast PV production, similar to a colocated resource. To account for the fact that PV+battery hybrid systems have a variable component, CAISO is proposing to implement a "dynamic limit" for scheduling hybrid resources that updates every five minutes to account for resource forecasts, state of charge, and site charging needs.

The California PUC requires load-serving entities to procure resource adequacy on monthly and annual bases to meet forecasted load plus a 15% margin. The commission uses an effective load carrying capability (ELCC) methodology to assign a monthly capacity value to PV, and it assigns a capacity value to battery storage based on the amount it can discharge continuously for

---

[7] Reports can be found at "eLibrary: Federal Energy Regulatory Commission," FERC, https://elibrary.ferc.gov/eLibrary under docket number AD20-9-000.

[8] CAISO defines an eligible intermittent resource as a generating unit that (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. Eligible intermittent resources are subject to special data requirements.

4 hours. A PV+battery hybrid system's resource adequacy value and effective flexible capacity value is equal to the sum of its respective components, which is equivalent to a colocated resource. One small difference between colocated resources and hybrid resources is that the hybrid system is exempt from the resource adequacy availability incentive mechanism (RAAIM), which penalizes resources that underperform and credits resources that overperform. While the PV component of a colocated resource is exempt as well, the battery component participates in the RAAIM. Thus, the capacity payments to a hybrid system may be more or less than a similar colocated system depending on whether the RAAIM payments are positive or negative.

4.2 Electric Reliability Corporation of Texas (ERCOT)

The Electric Reliability Corporation of Texas (ERCOT) has initiated a stakeholder process to consider hybrid and colocated resource participation, with a focus on systems which include battery storage (Nicholson 2020). ERCOT currently recommends PV+battery resources to register as an "energy storage resource" because the battery part of the coupled system may charge from the grid. It is uncertain whether hybrid assets that contain PV resources would lose their classification as "intermittent renewable resources" and therefore participate like conventional generators, or whether the renewable portion would maintain its status when assessing deviation penalties.

ERCOT does not have a capacity market but instead has a high market cap of $5,000/MWh to incentivize investment in generation capacity. Historically ERCOT's market cap was $9,000/MWh, but was lowered to $5000/MWh at the beginning of 2022 (Texas PUC 2022). The energy-only approach ERCOT takes means resources are credited for the ex-post amount of energy produced during peak periods instead of an ex-ante calculation of how much the resource will be expected to be available.

4.3 Pennsylvania, New Jersey, and Maryland Interconnection (PJM)

Though no hybrid resources are currently operating in the PJM Interconnection, PJM allows both colocated resources participating as separate assets and hybrid resources that participate as a single resource (PJM 2021b). Hybrid resources would participate in the energy market using the participation model of the larger "parent" fuel type.

PJM has a formal yearly capacity market, called the Reliability Pricing Model, which ensures long-term grid reliability by procuring capacity for the following 3 years. Hybrid resources in PJM are currently allocated a capacity credit based on the sum of component parts (PJM 2021b). The exception to this rule is with battery systems which cannot be charged from the grid, in which case the capacity is based on the primary fuel type. Starting in the 2023/2024 delivery year (whose first auction is in December 2021), PJM is set to transition capacity accreditation to an ELCC methodology (PJM 2021a). Under the new methodology, the battery component of a hybridized system will receive a different capacity credit from a standalone battery system of the same size. Table 4 shows the capacity credit by class and delivery year. Standalone battery storage initially is given a higher capacity credit than a hybridized battery, but hybridized battery storage has a higher capacity credit in the 2028–2030 delivery years. Thus, the value of hybridization relative to separately operated or colocated systems varies by year.

Table 4. PJM ELCC Capacity Factor Ratings for Select Classes

Values are from (PJM 2021a).

ELCC Class	2023	2024	2025	2026	2027	2028	2029	2030
4-hr Battery	83%	84%	77%	70%	72%	70%	69%	76%
PV hybrid loosely coupled 4-hr battery component	82%	80%	73%	65%	69%	72%	74%	87%
PV hybrid tightly coupled 4-hr battery component	82%	80%	72%	63%	69%	72%	74%	86%
PV fixed	38%	36%	32%	31%	29%	27%	25%	21%
PV tracking	54%	52%	48%	44%	42%	39%	36%	31%

4.4 Midwest Independent System Operator (MISO)

At the time of writing, The Midwest Independent System Operator (MISO) has 30 hybrid resource proposals in its interconnection queue, primarily from PV+battery systems (MISO 2021a). These hybrid resources can participate under any of the three already established participation models of Generation Resource, Dispatchable Intermittent Resource, or Stored Energy Resource—Type II. In August, 2021, MISO submitted revised tariff language which "establishes a methodology for accrediting Hybrid Resources in the MISO Resource Adequacy construct" (MISO 2021b).

MISO calculates the capacity credit of new hybrid resources as the lesser of (a) the sum of each individual component's capacity credit and (b) the interconnection limit. Once sufficient data are available for an operating hybrid system, then its capacity credit will be determined based on historical performance and availability during the top 8 daily peak hours per relevant season, along with the type and volume of interconnection service (MISO 2021b). Depending on the system's historical performance during these peak hours, the hybrid system could receive a higher or lower capacity credit than a similarly sized colocated system.

4.5 Southwest Power Pool (SPP)

Though SPP is still in the early stages of determining how to integrate hybrid resources, there is considerable interest in colocated resources and hybrids, especially with systems that contain a battery storage component, as a means to control resource variability and better utilize transmission assets (SPP 2021). There is currently no unique participation model for hybrid resources, which instead participate under the Generating Unit registration type (SPP 2021). SPP is considering an approach to crediting hybrid resources based on the sum of constituent parts while accounting for limitations based on generator interconnection agreement and physical factors such as inverter size (SPP 2021).

4.6 ISO New England (ISO-NE)

The Independent System Operator New England (ISO-NE) is proposing two colocated and hybrid options (Rastegar and Smith 2020). A hybrid system may participate as (a) a single, non-intermittent generation capacity resource, similar to a traditional generator or (b) a single "intermittent power resource," for systems where "the intermittent component is the predominant portion of the asset" (Rastegar and Smith 2020). The first option allows the hybrid to participate in all markets but foregoes the benefits of being classified as an intermittent power resource (meaning hybrids are subject to nonperformance penalties); the second option does not allow the hybrid to participate in regulation or reserve markets but maintains the intermittent power resource status (and thus exemption from nonperformance penalties) (Rastegar and Smith 2020).

ISO-NE bases the capacity credit of battery storage on how much it can discharge for 2 hours. For PV, it uses an exceedance method to determine the capacity credit. The median for summer and winter peak periods during the previous 5 years are averaged to determine the capacity credit for each respective season. As currently proposed, both colocated and hybrid PV+battery systems will have a capacity equal to the sum of capacities for each component (Rastegar and Smith 2020).

4.7 New York Independent System Operator (NYISO)

In March, 2021, FERC accepted NYISO proposed changes to its tariff, which implemented a participation model for colocated storage resources (FERC 2021a). NYISO is actively considering separate participation rules for *hybrid* resources, which will allow a PV+battery system to participate as a single resource. As part of the development process, NYISO intends to have revised capacity valuations for hybrid resources for its capacity accreditation in place by May 1, 2023 (NYISO 2021).

5 Conclusions and Future Research Needs

Grid operators are currently considering whether market structures should be modified to determine the resource adequacy contributions of PV+battery systems, and the rules of how such systems are credited for capacity are still being written in many market regions (FERC 2021b). In response to these active regulatory discussions, this report summarized key considerations for PV+battery resources, discussed markets for capacity, surveyed current RTO/ISO market rules applying to PV+battery, and surveyed the varying ways grid operators are allowing PV+battery to participate in capacity markets or otherwise contribute to resource adequacy requirements. The extent to which PV+battery systems can provide and be compensated for capacity, along with the rules regarding capacity payments for PV+battery systems, will play a critical role in determining the amount of PV+battery capacity that gets built.

Even without the influence of hybrids, the rapidly increasing share of variable resources and battery storage on the U.S. bulk power system is causing grid operators to reassess their capacity accreditation methods. For example, PJM, NYISO, and SPP are considering (or already implementing) a shift from simpler approximation methods to more complex, and potentially more accurate, probabilistic methods (Sun et al. 2021). At the same time, grid operators are evaluating whether unique approaches (or modifications) are needed for PV+battery systems. Approaches that ignore the impacts of coupling could (a) overvalue particular resources potentially resulting in capacity shortages or (b) undervalue and potentially exclude resources, resulting in market inefficiencies, including revenue sufficiency challenges. Well-designed rules could allow markets to receive the full benefits hybrid systems can offer without overcompensating them for the services they provide.

While it may be possible to adequately represent colocated PV+battery resources with existing calculation approaches, hybridization modifies the impacts of interconnection limits and can introduce inverter constraints and limitations on the ability to charge the battery. Market operators must determine whether to calculate capacity credits for hybrid systems based on (a) the "sum of parts" approach for each component or (b) an analysis of the fully integrated hybrid system. The sum of parts approach is simpler and provides clarity to the process, but determining capacity credits based on the integrated system may better account for the limitations imposed by the PV and battery component interactions in a hybrid configuration. Such interactions are especially important to consider for DC-coupled hybrids—with a single shared inverter—in which specific design parameters (e.g., a large battery) would likely lead to a joint capacity credit that is lower than the sum of parts approach would suggest.

Simplified approaches for calculating capacity value may not be adequate for capturing the full value of PV+battery hybrids (and other flexible resources), particularly in a grid with significant shares of variable generation. While the transparency of simplified approaches—including "sum of parts" and capacity factor-based approximation methods for calculating hybrid system capacity values—is appealing, it may be outweighed by the drawback of limited accuracy and risks to maintaining resource adequacy in the most cost-effective manner. As a result, there is a general effort among grid operators to transition to probabilistic reliability-based methods.

Because of the growth in PV+battery systems and their increasing complexity—involving multiple configurations and likely increases in DC/AC ratios—it is important that research in capacity value methods continue, along with development of transparent algorithms and stakeholder vetted software tools. These improved tools and methods will help address not only the growing challenges associated with PV+battery hybrids, but they will also provide improved approaches for modeling complex resources such as advanced demand response.

6 References

Ahlstrom, Mark, Andrew Gelston, Jeffrey Plew, and Lorenzo Kristov. 2019. "Hybrid Power Plants–Flexible Resources to Simplify Markets and Support Grid Operations."

Bolinger, Mark, Will Gorman, Joe Rand, Ryan Wiser, Seongeun Jeong, Joachim Seel, Cody Warner, and Ben Paulos. 2021. "Hybrid Power Plants: Status of Installed and Proposed Projects." LBNL. https://emp.lbl.gov/publications/hybrid-power-plants-status-0.

Bolinger, Mark, Joachim Seel, and Dana Robson. 2019. "Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States (2019 Edition)." https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2019_edition_final.pdf.

CAISO. 2017. "Resource Adequacy Availability Incentive Mechanism Modification: Draft Final Proposal." September 21, 2017. https://www.caiso.com/Documents/DraftFinalProposal-RAAIMCalculationModifications-clean.pdf.

———. 2018. "AWE Grid History Report." https://www.caiso.com/Documents/Alert_WarningandEmergenciesRecord.pdf.

———. 2021a. "Summary of Restricted Maintenance Operations, Alert, Warning, Emergency, and Flex Alert Notices Issued from 1998 to Present." https://www.caiso.com/Documents/AWE-Grid-History-Report-1998-Present.pdf.

———. 2021b. "Informational Report of the California Independent System Operator Corporation." Docket No. AD20-9-000. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20210719-5160.

Denholm, Paul, Wesley Cole, A. Will Frazier, Kara Podkaminer, and Nate Blair. 2021. "Storage Futures Study: The Four Phases of Storage Deployment: A Framework for the Expanding Role of Storage in the U.S. Power System." NREL/TP-6A20-77480. National Renewable Energy Lab. (NREL), Golden, CO (United States). https://doi.org/10.2172/1763974.

Denholm, Paul L, and Robert M Margolis. 2018. "The Potential for Energy Storage to Provide Peaking Capacity in California Under Increased Penetration of Solar Photovoltaics." NREL/TP-6A20-70905, 1427348. https://doi.org/10.2172/1427348.

Denholm, Paul L., Robert M. Margolis, and Joshua D. Eichman. 2017. "Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants: Report Summary." NREL/PR-6A20-69061. National Renewable Energy Lab. (NREL), Golden, CO (United States). https://doi.org/10.2172/1378439.

Dent, C. J., R. Sioshansi, J. Reinhart, A. L. Wilson, S. Zachary, M. Lynch, C. Bothwell, and C. Steele. 2016. "Capacity Value of Solar Power: Report of the IEEE PES Task Force on Capacity Value of Solar Power." In *2016 International Conference on Probabilistic Methods Applied to Power Systems (PMAPS)*, 1–7. https://doi.org/10.1109/PMAPS.2016.7764197.

EPRI. 2016. "Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs." Electric Power Research Initiative.

ERCOT. 2014. "ERCOT Nodal 101 Training." http://www.ercot.com/content/wcm/training_courses/14/Nodal_101.pdf.

Feldman, David, Kevin Wu, and Robert Margolis. 2021. "H1 2021 Solar Industry Update." NREL/PR-7A40-80427. National Renewable Energy Lab. (NREL), Golden, CO (United States). https://doi.org/10.2172/1808491.

FERC. 2018. *Order No. 841*. https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

———. 2020. "Technical Conference Regarding Hybrid Resources." https://www.ferc.gov/news-events/events/technical-conference-regarding-hybrid-resources-docket-no-ad20-9-000-07232020.

———. 2021a. "Order Accepting Proposed Tariff Revisions to Implement Participation Model for Co-Located Storage Resoruces." Federal Energy Regulatory Comission. https://elibrary.ferc.gov/eLibrary/filedownload?fileid=15749175.

———. 2021b. "Hybrid Resources White Paper." May 2021. https://www.ferc.gov/media/hybrid-resources-white-paper.

Flores-Espino, Francisco, Tian Tian, Ilya Chernyakhovskiy, Ilya Chernyakhovskiy, and Mackay Miller. 2016. "Competitive Electricity Market Regulation in the United States: A Primer." NREL/TP-6A20-67106. National Renewable Energy Lab. (NREL), Golden, CO (United States). https://doi.org/10.2172/1336561.

Frazier, Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. 2021. "Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector." Energy.Gov. 2021. https://www.energy.gov/eere/analysis/storage-futures-study-economic-potential-diurnal-storage-us-power-sector.

Garver, L. L. 1966. "Effective Load Carrying Capability of Generating Units." *IEEE Transactions on Power Apparatus and Systems* PAS-85 (8): 910–19. https://doi.org/10.1109/TPAS.1966.291652.

Gorman, Will, Andrew Mills, Mark Bolinger, Ryan Wiser, Nikita Singhal, Erik Ela, and Eric O'Shaughnessy. 2020. "Motivations and Options for Deploying Hybrid Generator-plus-Battery Projects within the Bulk Power System." *Electricity Journal* 33 (5): 106739.

Gramlich, Rob, Michael Goggin, and Jason Burwen. 2019. "Enabling Versatility: Allowing Hybrid Resources to Deliver Their Full Value to Customers." Energy Storage Association. https://energystorage.org/wp/wp-content/uploads/2019/09/2019.9.16-GridStrategies-ESA-White-Paper-on-Hybrid-Resources.pdf.

Horton, Horace. 2017. "Overview of Certain ICAP Sanctions and Deficiency Charges," November, 18.

ISO-NE. 2018. "Forward Capacity Market (FCM) Qualification Examples for Storage Technologies." https://www.iso-ne.com/static-assets/documents/2016/03/fcm_qualification_examples_for_storage_technology_final.pdf.

Konidena, Rao. 2016. "Battery Energy Storage in MISO," November, 19.

Madaeni, Seyed Hossein, Ramteen Sioshansi, and Paul Denholm. 2012. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704. National Renewable Energy Lab. (NREL), Golden, CO (United States). https://www.nrel.gov/docs/fy12osti/54704.pdf.

Milligan, Michael. 2011. "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning (IVGTF1-2)." Presented at the Joint NERC-UWIG Workshop, Kansas City, Kansas, April 12. https://www.nrel.gov/docs/fy11osti/51485.pdf.

Milligan, Michael, Bethany Frew, Aaron Blooom, Erik Ela, Audun Botterud, Aaron Townsend, and Todd Levin. 2016. "Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Revenue Sufficiency and Long-Term Reliability." *Electricity Journal* 29: 26–38.

Milligan, Michael, Bethany Frew, Eduardo Ibanez, Juha Kiviluoma, Hannele Holttinen, and Lennart Söder. 2017. “Capacity Value Assessments of Wind Power.” *WIREs Energy and Environment* 6 (1): e226. https://doi.org/10.1002/wene.226.
Mills, Andrew, and Pia Rodriguez. 2019. “Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities.” Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/drivers-resource-adequacy.
Mills, Andrew, and Ryan Wiser. 2012. “Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California.” 2012.
MISO. 2017. “Business Practices Manual: Resource Adequacy (Redline).” August 25, 2017. https://extranet.misoenergy.org/api/documents/getbymediaid/34835.
———. 2018. “2018/2019 Planning Resource Auction Results.” April 13, 2018. https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf.
———. 2021a. “Report on Hybrid Resources of the Midcontinent Independent System Operator.”
———. 2021b. “Midcontinent Independent System Operator, Inc. Proposed Revisions to Tariff for Accreditation of Hybrid Resources.” https://cdn.misoenergy.org/2021-08-06%20Docket%20No.%20ER21-2620-000577311.pdf.
Murphy, Caitlin, Anna Schliefer, and Kelley Eurek. 2021. “A Taxonomy of Systems That Combne Utility-Scale Renewable Energy and Energy Storage Technologies.” *Renewable and Sustainable Energy Reviews* 139. https://www.sciencedirect.com/science/article/pii/S1364032121000083.
NERC. 2018. “Probabilistic Adequacy and Measures: Technical Reference Report.” April 2018. https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf.
Nicholson, Emma. 2020. “Facilitating Hybrid and Co-Located Resource Participation in Wholesale Electricity Markets.” American Wind Energy Association.
NYISO. 2021. “Hybrid Resources Report of the New York Independent System Operator, Inc.”
Parent, Christopher, Matthew Hoyt, and Cali Clark. 2021. “Resource Adequacy Constructs in Organized Wholesale Markets.” Exeter Associates, Inc. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwj5rpvmq5v2AhUoTt8KHUqFAF4QFnoECCQQAQ&url=https%3A%2F%2Fwww.pjm.com%2F-%2Fmedia%2Fcommittees-groups%2Fuser-groups%2Fpieoug%2F2021%2F20210505%2F20210505-resource-adequacy-constructs-in-organized-wholesale-markets-report.ashx&usg=AOvVaw0Gml9D4BGrk6aZh0R5iP76.
Peralta, Sabely. 2017. “FCM Pay for Performance Evaluations,” October, 33.
PJM. 2014. “Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events.”
———. 2017a. “Intermittent Resource Participation in RPM for 2020/21 and Beyond.” https://www.pjm.com/-/media/committees-groups/subcommittees/irs/20170317/20170317-item-08-intermittent-resource-participation-in-rpm.ashx.
———. 2017b. “RPM 101 Overview of Reliability Pricing Model.” https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx?la=en.

———. 2017c. “RPM 301 Performance in Reliability Pricing Model.” https://www.pjm.com/-/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-301-performance-in-reliability-pricing-model.ashx?la=en.

———. 2018. “Historical Emergency Procedures.” https://www.pjm.com/-/media/committees-groups/committees/elc/postings/historical-performance-assessment-hours.ashx?la=en.

———. 2021a. “July 2021 ELCC Report.” https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-for-july-2021-results.ashx.

———. 2021b. “Response to Hybrid Resources, Docket No. AD20-9-000.”

Rastegar, Shahab, and Doug Smith. 2020. “Market Participation Options for Combined Intermittent/Electric Storage Facilities.” ISO New England. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjt6-Hmzdz0AhWTjIkEHaWRDV0QFnoECAcQAQ&url=https%3A%2F%2Fwww.iso-ne.com%2Fstatic-assets%2Fdocuments%2F2020%2F04%2F20200408-co-located-market-participation.pdf&usg=AOvVaw3TrYRXEhPyW9DNoAjI6STv.

Schlag, Nick, Zachary Ming, and Arne Olson. 2020. “Adding It All up: Counting the Capacity Contribution of Variable and Duration-Limited Resources.” *Utility Dive*, September. https://www.utilitydive.com/news/adding-it-all-up-counting-the-capacity-contribution-of-variable-and-durati/584843/.

Schleifer, Anna, Caitlin Murphy, Wesley Cole, and Paul Denholm. 2022. “Exploring the Design Space of PV-plus-Battery System Configurations under Evolving Grid Conditions.” *Applied Energy* 308 (118339).

SEIA. 2018. “Reverse Auction Mechanism.” SEIA. 2018. /initiatives/reverse-auction-mechanism.

Sivaram, Varun, and Shayle Kann. 2016. “Solar Power Needs a More Ambitious Cost Target.” *Nature Energy* 1 (4): 1–3. https://doi.org/10.1038/nenergy.2016.36.

Spees, Kathleen, Hannes Pfeifenberger, Tony Lee, Judy Chang, and Roger Lueken. 2017. “Incentive and Penalty Mechanisms for Capacity Resources.” Brattle Group. https://www.aeso.ca/assets/Uploads/Brattle-Penalty-Mechanisms.pdf.

SPP. 2020. “Resource Adequacy Workbook Instruction Manual.” https://www.spp.org/Documents/45078/Resource%20Adequacy%20Workbook%20Instruction%20Manual%2020201230.docx.

———. 2021. “Report on Hybrid Resources of Southwest Power Pool, Inc.” Docket No. AD20-9-000.

Sun, Y, B Frew, Levin T, RB Hytowitz, J Kwon, AD Mills, Q Xu, M Heidarifar, N Singhal, and P Mello. 2021. “Research Priorities and Opportunities in United States Competitive Wholesale Electricity Markets.” NREL/TP-6A20-77521. NREL. https://www.nrel.gov/docs/fy21osti/77521.pdf.

Texas PUC. 2022. “25.505 Reporting Requirements and the Scarcity Pricing Mechanism in the Electric Reliability Council of Texas Power Region.” https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjg4v2Khb71AhWKpnIEHXPdD1MQFnoECAwQAw&url=https%3A%2F%2Fwww.puc.texas.gov%2Fagency%2Frulesnlaws%2Fsubrules%2Felectric%2F25.505%2F25.505.pdf&usg=AOvVaw3NovLXafp0W4AxnXZT-h1p.

Appendix. Duration Estimates Based on Historical Events

PV+battery systems could provide support to capacity requirements if the typical duration of the paired system were assessed in relation to historical data from capacity events. Capacity events or emergencies are not stochastic, however, as they are usually associated with regional weather and climate patterns. Reliability hours are intended to assess a resource based on the time frame when capacity shortages are most likely to occur. RTO/ISOs often use different reliability hours—i.e., hours specific to their historical demand and past capacity events—to estimate the capacity credit of PV and battery resources. Because there is a disparity in how PV and battery capacity credit can be determined, it is challenging to identify the true value of the paired system using this methodology.

One key consideration in establishing an appropriate capacity duration requirement for PV+battery systems is the historical duration of capacity events. To assess this, we assembled a database for this report recording the time of day, duration, and type of capacity events in both PJM and CAISO.[9] The database includes capacity events between 2008 and 2017 that were considered alerts, actions, warnings, or emergencies—these escalating events are called by the RTO/ISO when capacity shortages are imminently anticipated or expected. Excluded from this analysis were prescheduled maintenance operations causing capacity shortages and grid events caused by significant externalities (i.e., a California wildfire that caused an 8-day long emergency). For the purpose of analysis, the duration of events is the only variable analyzed. This analysis did not model what future capacity events may look like but instead studied the temporal characteristics of past capacity events.

The median duration of a capacity event in CAISO is close to 7 hours, and a few high outliers occur in the spring and summer (Figure A-1). The median duration is briefer in PJM—close to 3.5 hours in the fall and winter and slightly above 2 hours in the spring and summer. For PJM, the 10-hour storage duration requirement applied to storage resources exceeds almost all historical occurrences. Meanwhile in CAISO, the 4-hour storage rule could be too short for many events if storage were expected to output power for the entirety of a capacity event; however, if storage were intended to supplement PV during a capacity event, 4 hours could be an appropriate requirement. RTO/ISOs could consider further analysis of the duration of their capacity events in order to determine whether current minimum duration requirements are appropriate.

[9] Sources include (CAISO 2018; PJM 2018); the assembled database includes events between 2008 and 2017.

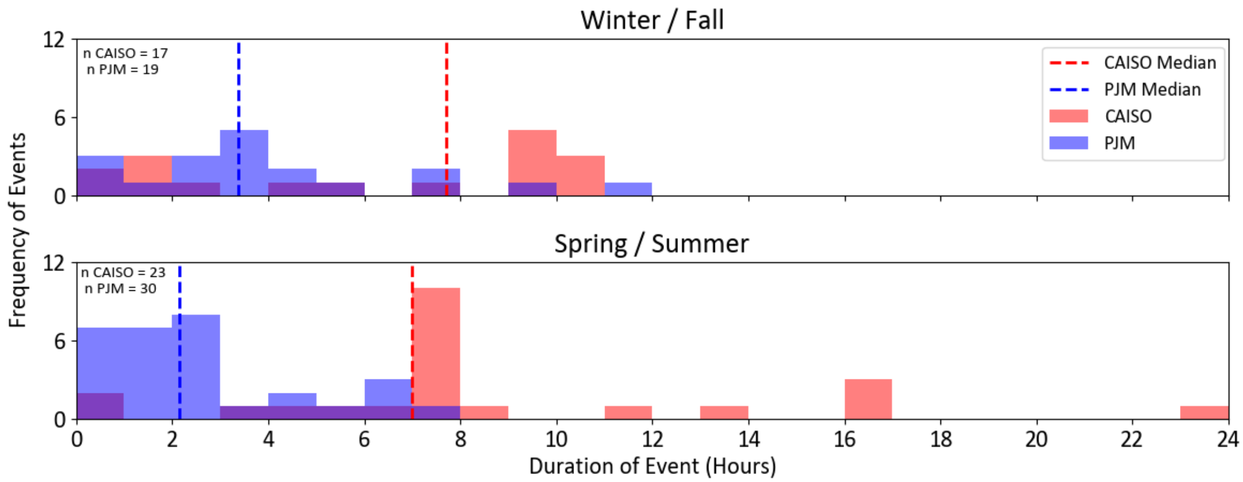

Figure A-1. Histogram of duration of capacity events in PJM and CAISO by season

The authors created the figure using data from CAISO (2018c) and PJM (2018b).

In addition to analyzing the duration of capacity events, we also analyzed the timing of events. Figure A-2 displays the mid-hour of capacity events by season. Though CAISO's capacity events generally occur in the afternoon and early evening regardless of season, PJM is evening-peaking in the summer, and it experiences two daily peaks in the winter. This is reflected in PJM's PV reliability hours, which are 6–9 a.m. and 6–9 p.m. in winter (Table 4). PJM's summer reliability hours of 3–8 p.m. do not closely match the historical mid-hours of capacity events there—one-third of spring and summer capacity events in PJM have midpoints before the summer reliability hours, a time of the day when PV is likely providing more reliable generating capacity than it is during the reliability hours by which it was assessed. In this regard, PJM's summer PV reliability hours could be undervaluing the capacity value solar provides during the times of day when capacity events are likely to occur. Adding a storage system with a short duration of even 1–2 hours to a PV system could increase its ability to deliver power during the times of day when capacity events are most likely to occur.

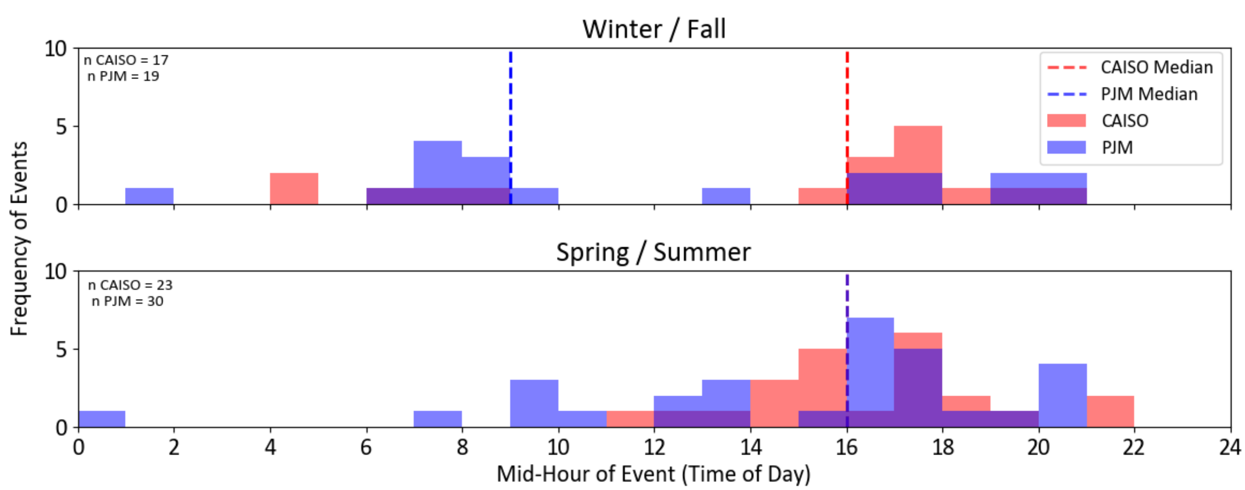

Figure A-2. Histogram of mid-hour of capacity events in PJM and CAISO by season

The authors created the figure using data from CAISO (2018c) and PJM (2018b).