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Motivations and options for deploying hybrid generator-plus-battery projects within the bulk power system

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ABSTRACT

Growth in U.S. utility-scale hybrid battery projects suggests potential advantages currently outweigh disadvantages. Today's 4.6 GW of hybrid capacity is accompanied by 14.7 GW in the immediate development pipeline, and 69 GW in select interconnection queues. Analysis using wholesale market prices finds that additional revenues from adding a 4-hour battery to solar can exceed additional costs. However, realizing hybrid projects' full value depends on nascent strategies for integrating them in current/future wholesale market design paradigms.

1. Introduction

Variable renewable energy (VRE) technologies, such as wind and solar photovoltaics (PV), have proliferated in the United States with the help of technology improvements, cost reductions, and policy support. In 2018, average annual VRE penetrations reached about 9% nationwide and up to twice that high in some regions (Bolinger et al., 2019; EIA, 2019; Wiser et al., 2018). Competitive VRE costs and continued policy support suggest that U.S. VRE penetrations will continue to rise (Barbose, 2019; Lazard, 2018). Because of the variability and uncertainty associated with VRE generation (Brouwer et al., 2014; Engeland et al., 2017), integrating high VRE levels onto electricity grids reliably and cost-effectively may require strategies that increase grid flexibility (Denholm and Hand, 2011; Elliston et al., 2012; Mai et al., 2014; Shaner et al., 2018).

Energy storage is one strategy for increasing grid flexibility and facilitating large VRE penetrations (Braff et al., 2016; Paul L Denholm et al., 2019a; Shaner et al., 2018; Ziegler et al., 2019). Although many storage technologies exist (Akinyele and Rayudu, 2014), declining battery costs have helped stimulate interest in integrating batteries onto U.S. grids at an unprecedented scale (Cole and Frazier, 2019; Kittner et al., 2017). Such battery capacity could be physically sited at various locations within a grid system; it need not be co-located with VRE technologies or other generator types to provide benefits. Siting choices depend on various considerations including, but not limited to, effective VRE integration. However, project developers have demonstrated increasing interest in "hybrid" projects that co-locate generation with batteries at the point of interconnection (Bolinger et al., 2019).

This article explores the advantages, disadvantages, development trends, near-term value proposition, and market participation options for utility-scale hybrid battery projects in the United States, with a focus on PV-battery and wind-battery hybrids. The concept of hybridization can encompass various technologies and configurations, such as PV co-located with geothermal or wind (Ramli et al., 2016), concentrating solar power with thermal storage, wind with pumped hydro storage, combined-cycle plants, and combined heat and power systems (Arent et al., 2018). Hybrid systems can also consist of elements that are not co-located; virtual hybrids can employ distributed combinations of demand-side response, generation, and batteries to participate in wholesale power markets (Anderson et al., 2016). This article, however, addresses only co-located utility-scale generation and battery

Abbreviations: AC, alternating current; AS, ancillary services; CAISO, California Independent System Operator; DC, direct current; EIA, U.S. Energy Information Administration; ERCOT, Electric Reliability Council of Texas; ESR, electric storage resource; FERC, Federal Energy Regulatory Commission; IRP, integrated resource plan; ISO, independent system operator; ISO-NE, ISO New England; ITC, investment tax credit; MISO, Midcontinent Independent System Operator; NYISO, New York Independent System Operator; PPA, power-purchase agreement; PV, photovoltaic; RTO, regional transmission organization; SOC, state of charge; SPP, Southwest Power Pool; VRE, variable renewable energy

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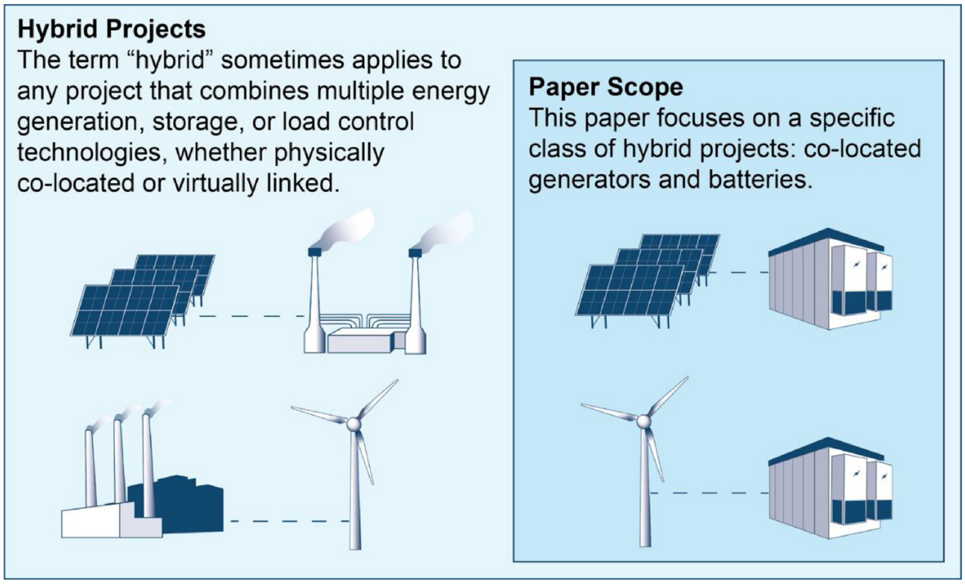

Fig. 1. Scope of hybrid projects covered in this article.

technologies, which are the focus of current commercial activity in the United States (Fig. 1). The article is meant to inform electric-sector stakeholders—including industry participants, regulators, market organizers, analysts, and policymakers—who are seeking to understand these types of projects and integrate them into wholesale markets.

In the remainder of the article, Section 2 discusses the key advantages and disadvantages of hybridization, Section 3 outlines hybrid project development trends, and Section 4 describes a simple optimization model for comparing the market value of hybrid projects with recent power-purchase agreement (PPA) prices. Section 5 covers wholesale market design operational challenges and hybrid participation options, and Section 6 concludes with a discussion of open research questions.

2. To hybridize or not to hybridize? Pros and cons of grid-level hybrid projects

This section qualitatively discusses the advantages and disadvantages of directly pairing different grid-connected resources in a hybrid configuration (Fig. 2). Although hybrid systems can include distributed technologies and behind-the-meter systems (Gagnon et al., 2017; McLaren et al., 2019), we address only utility-scale battery and hybrid systems (Akhil et al., 2013; Ericson et al., 2018, 2017). In particular, we focus on the pros and cons of hybridizing vs. independently developing standalone battery and generator projects in wholesale markets.

As summarized in previous literature, the economic arguments for hybridizing plants focus on opportunities to (1) reduce project costs, and (2) increase project market value. Opportunities to reduce project costs arise from policy incentives, construction and operational synergies, and transaction cost mitigation. Federal policy incentives for renewable hybrid projects, most importantly the investment tax credit (ITC), reduce capital costs relative to the cost of independently sited battery projects. Under current federal policy, the ITC provides a prorated income tax credit of up to 30 % of battery costs if the batteries are charged completely by onsite solar and 22.5 % if charged 75 % by onsite solar (Elgqvist et al., 2018; Gramlich et al., 2019).[1] However, this large incentive for hybridization will be phased down from 30 % to 10 % by 2022 and could be eliminated if the ITC is granted for standalone battery projects (Gheorghiu, 2019).

Project construction synergies include shared permitting and siting costs, shared power electronic and general power plant equipment, and shared interconnection agreements. Although difficult to quantify without more real-world examples, studies suggest that initial solar-plus-battery hybrid system capital costs can be 8% lower than the capital costs of independently sited systems (Denholm et al., 2017; Fu et al., 2018). Increased transmission utilization by hybrids can reduce transmission costs. However, this potential advantage is not always captured fully by the developer in the form of interconnection cost savings, because transmission costs are partially socialized (Gorman et al., 2019). Finally, hybrid projects can lower the transaction costs of securing an offtaker, because negotiating the terms of one contract rather than multiple contracts can reduce administrative burdens. Similarly, creating just one (or relying on an existing) interconnection agreement and queue position can be less expensive and quicker than initiating a separate interconnection request for multiple standalone projects.

Market value benefits from hybridization involve design and operations optimization as well as market participation rules. Various operational strategies can boost revenue from hybrid projects relative to standalone projects. For conventional thermal generator-plus-battery hybrids, cycling the battery may be less expensive than the wear and tear from generator cycling. For coupled PV-battery hybrid systems, batteries provide the extra benefit of recapturing "clipped" energy from oversized solar systems, and direct current (DC) coupled systems enable low-voltage harvesting periods when inverters cannot generate power from the solar system (Larsen, 2019). Furthermore, batteries provide precise control of ramping to either capture more energy from VRE systems,[2] which might be constrained owing to independent system operator (ISO)/regional transmission organizations (RTO) ramp limits, or increase ancillary service (AS) market participation for all generators (Ericson et al., 2018). Ultimately, market design rules may value hybrid projects differently than standalone resources for regulatory and policy reasons. For example, if a utility or ISO/RTO imposes ramp-rate limits on VRE or disallows VRE from participating in the AS market, then hybrids can help resolve these market design limits. Additionally, a utility or ISO/RTO could impose energy requirements on certain market products that might limit standalone storage's ability to participate but would be resolved by a hybrid resource. Evolving market design parameters could give rise to more examples of designs that support hybridization of energy-limited resources like batteries with generation technologies, or hybridization of variable resources

[1] Projects do not qualify for the ITC if less than 75% of energy charging comes from solar.

[2] In addition, capturing extra energy could create value by capturing renewable energy credits.

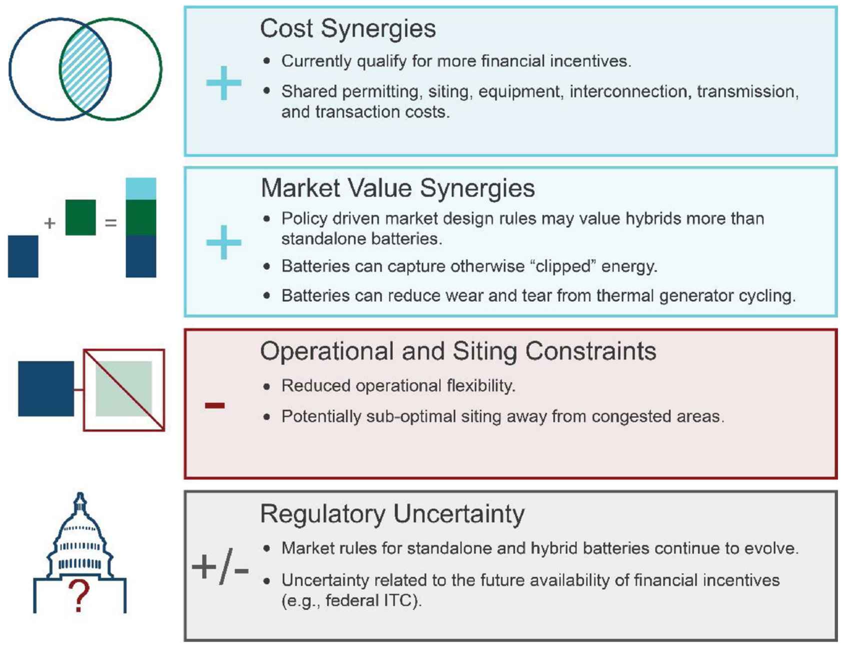

Fig. 2. Pros (+) and cons (-) of battery hybrid projects.

like renewables with batteries (Ahlstrom et al., 2019).

Hybridization also poses challenges. First, coupling a battery system to a generator behind a point of interconnection might result in operational constraints that reduce the battery's ability to provide maximum value during critical times. These constraints will depend on the nature of the coupling—e.g., alternating current (AC) vs. DC—as well as the size of the shared interconnection. In the near term, meeting current ITC rules will reduce the ability of a hybrid plant to charge from the grid, which limits the independent operational value of the battery. Second, hybridization could result in suboptimal system siting. When developers site their conventional or VRE plants, they typically optimize based on fuel (or renewable resource), capacity factor, and cost considerations, but for hybrid systems these considerations might result in suboptimal battery siting, away from areas of congestion and load. Finally, the regulatory uncertainty surrounding direct financial incentives and rules for market participation designs could result in conditions that promote or hinder hybridization. Section 5 elaborates on market barriers and opportunities.

3. Hybrid project development trends

Figs. 3 and 4 summarize the capacity, battery ratio, and average duration of currently operating and publicly announced U.S. battery hybrid projects.[3] These data include all projects over 1 MW in size and therefore include some customer-sited projects, which may or may not participate in wholesale markets.[4] Overall, we identified 61[5] online hybrid projects and 88 proposed hybrid projects in the immediate development pipeline. In general, battery-to-generation ratios are larger for PV-battery projects than for wind and gas hybrids, and battery durations are longer for developing projects than for currently online hybrids. Details for each project can be found in the Appendix.

We also surveyed seven different interconnection queues administered by U.S. ISOs/RTOs.[6] Although these data overlap with the publicly announced pipeline projects identified above, they include a wider variety of projects that are not as far along in the development process. These data should be interpreted with caution: placing a project in the interconnection queue is a necessary step in project development, but being in the queue does not guarantee that a project will be built; often, fewer than 25 % of projects in the queues are built. A summary of the hybrid projects in these interconnection queues along with the online and pipeline projects are included in Table 1.

Fig. 5 shows the amount of all resources, including non-hybrids and standalone storage, working their way through these seven queues. The dark portions of the bars indicate the amounts paired with batteries. Fig. 6 focuses on the hybrid and standalone battery capacity in the queues, highlighting the significant amount that entered the queues in 2019.

Fig. 7 breaks down hybrid capacity in the queues by ISO/RTO. The queued capacity of wind and PV hybrids is largest in CAISO (California), where high VRE penetration creates grid-operation ("duck curve") challenges that can be at least partly alleviated by battery storage (Denholm et al., 2015). Table 2 shows the percentage of PV and wind generators in each ISO/RTO queue that includes hybridization. This table further reinforces the popularity of the hybridization model within CAISO as compared to other ISO/RTOs.

To capture information on non-ISO/RTO regions, we collected queue data for 30 additional utilities through 2018.[7] Fig. 8 plots data

[3] The currently operating hybrid project data are from U.S. Energy Information Administration (EIA) Form 860 (accessed 11/2019). The publicly announced projects are identified in the ABB Ventyx (accessed 12/2019) and EIA Form 860 (accessed 11/2019) databases. These projects were connected to formal press releases (often at the time of PPA execution) and corresponding public documents where possible.

[4] Some of these plants are likely co-located but may not be operationally linked. At a minimum, they share an interconnect, which may or may not limit operation.

[5] Four of these online projects represent 0.07 GW of hydro-battery hybrid projects, which were too small to report in the summary figures. Details on these projects can be found in the Appendix.

[6] We only include projects that were active in the queues at the end of 2019 but that had not yet been built; suspended projects are not included. These queues have an aggregated non-coincident (balancing authority) peak demand of about 50% of the U.S. total and cover all seven U.S. ISOs/RTOs: California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), PJM Interconnection, New York Independent System Operator (NYISO), and ISO New England (ISO-NE).

[7] The utilities represent 30% of U.S. aggregated non-coincident (balancing authority) peak demand. These data combined with the ISO/RTO data represent about 80% of total U.S. non-coincident peak demand.

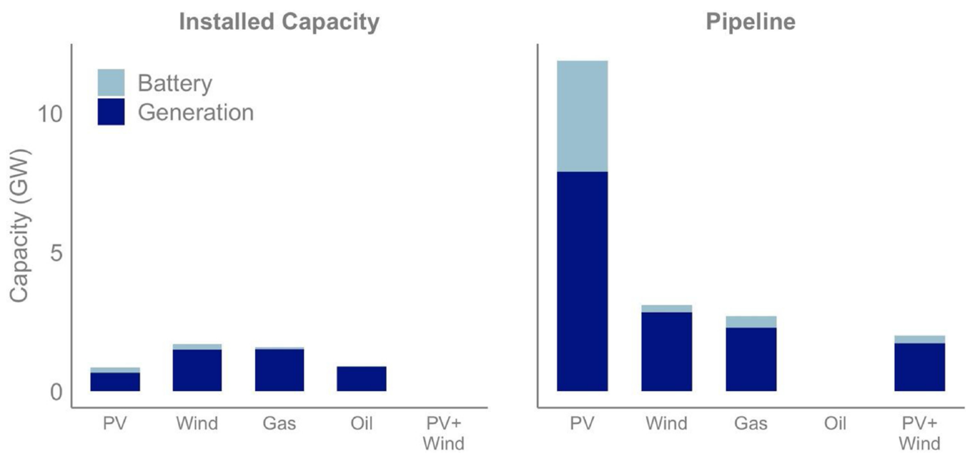

Fig. 3. Capacity of currently online hybrid projects (left) and development pipeline (right).

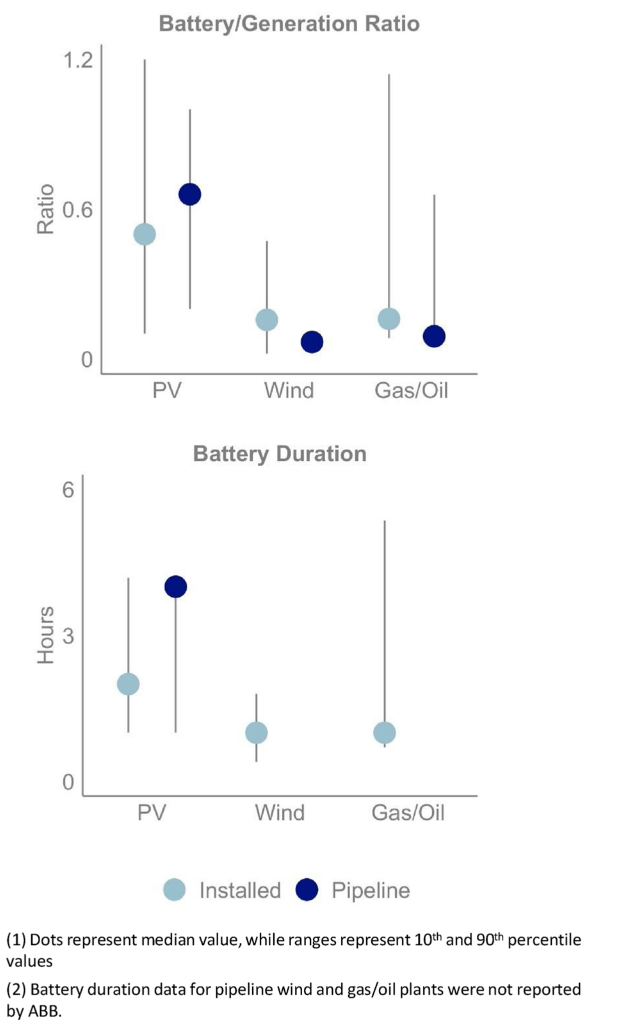

Fig. 4. Hybrid project battery-to-generation ratio and duration statistics for online and pipeline projects.

through 2018 for ISO/RTO and non-ISO/RTO regions, showing that the Southwest had 49 % of total PV-hybrid capacity at the end of that year.

4. Price and market value trends for hybrid projects

4.1. Hybrid power pricing

We collected PPA price information for 23 of the 109 online and pipeline PV-battery hybrid projects, 12 of which are in Hawaii, with the rest spread among Nevada, California, and Arizona. We were unable to find corresponding information on wind and fossil fuel hybrid projects. PPA prices for the analyzed PV-battery hybrid projects declined between 2015 and 2019 (Fig. 9). Hawaiian prices dropped from around \$120/MWh in 2015 to around \$70/MWh by the end of 2018. For continental U.S. projects, prices dropped from \$40–\$70/MWh in 2017 to \$20–\$30/MWh in 2018 and 2019. Hawaiian PV-battery hybrid projects are priced at a significant premium over those in California and the Southwest, which in part could be attributable to Hawaii's relatively higher cost of plant construction and/or higher electricity costs, but is also due to generally higher battery/generator ratios.

Six of these 23 PV-battery PPAs provide enough information to enable direct calculation of a battery adder (e.g., through separate capacity payments for the battery component). Fig. 10 shows incremental battery adders for PPAs with 4 h of battery storage, as a function of the ratio of battery-to-PV capacity. Based on this limited sample, a 4 -h battery that is sized at roughly 25 % of the PV capacity adds about \$4/MWh-delivered to the overall PPA price for the combined plant. As the battery capacity increases to 50 % and 75 % of the PV capacity, the levelized battery adder increases linearly to about \$10/MWh-delivered and \$14/MWh-delivered, respectively.

4.2. Hybrid market value analysis

To contextualize these PPA price trends, we estimate the wholesale market net revenues (i.e., the "market value") of hybrid projects relative to standalone wind, PV, and battery storage projects.[8] We limit our analysis to the California and Texas markets and energy and capacity prices from 2016 to 2018 owing to the ease of accessing market prices and relative proliferation of PV and wind projects in these states.[9] Our simple optimization model assumes that the operation of these projects will not change wholesale prices. We exclude AS prices, because AS markets are small compared to the large amount of hybrid batteries being proposed (Denholm et al., 2019b). We also assume that

[8] PV profiles are modeled from weather data for an individual plant in California and Texas. Wind profiles are aggregate production profiles in the SP15 region for California and Western region for Texas. We use the same profiles for both standalone and hybrid modeling.

[9] California prices are from CAISO's SP15 node, while Texas prices are from ERCOT's West Hub. We collect real-time 15-minute and hourly prices. California capacity prices are based on monthly bilateral capacity contract prices reported by investor-owned utilities to the California Public Utilities Commission. We use the 85th percentile of the capacity contract prices at the CAISO system level. Texas does not have a capacity market, so we rely only on its energy prices.

Table 1
Summary of online and proposed hybrid projects.

	PV Hybrid				Wind Hybrid				Natural Gas Hybrid			
	Projects *(Count)*	Gen. Capacity *(MW)*	Battery Capacity *(MW)*	Avg. Battery Duration *(hours)*	Projects *(Count)*	Gen. Capacity *(MW)*	Battery Capacity *(MW)*	Avg. Battery Duration *(hours)*	Projects *(Count)*	Gen. Capacity *(MW)*	Battery Capacity *(MW)*	Avg. Battery Duration *(hours)*
Installed (EIA 860)	34	706	226	2.7	13	1,497	199	1.7	5	1,504	72	1.1
Announced Pipeline (ABB/EIA 860)	75	7,850	3,948	3.1	5	2,837	250	NA	3	2,275	426	NA
Interconnection Queues (w/battery capacity)	158	43,209	28,305	NA	17	6,560	1,773	NA	1	244	445	NA
Interconnection Queues (w/o battery capacity)	117	17,900	NA	NA	3	973	NA	NA	2	237	NA	NA

Note: Only four of the seven queues surveyed provide corresponding data on storage capacity of hybrids, so we break the queues into those that do and do not report battery capacity.

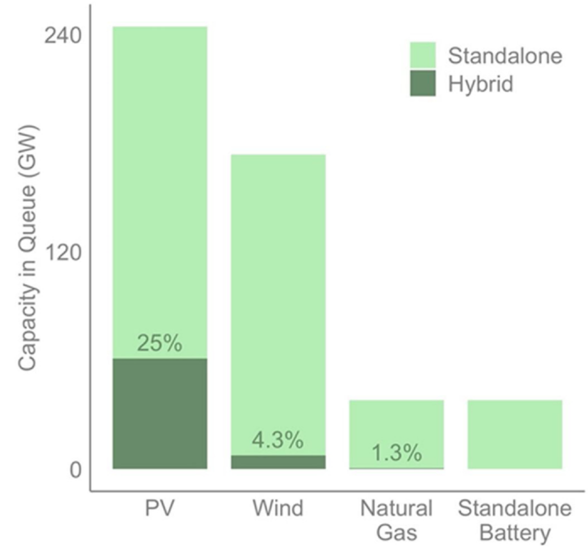

Fig. 5. Resource capacity in seven selected interconnection queues.

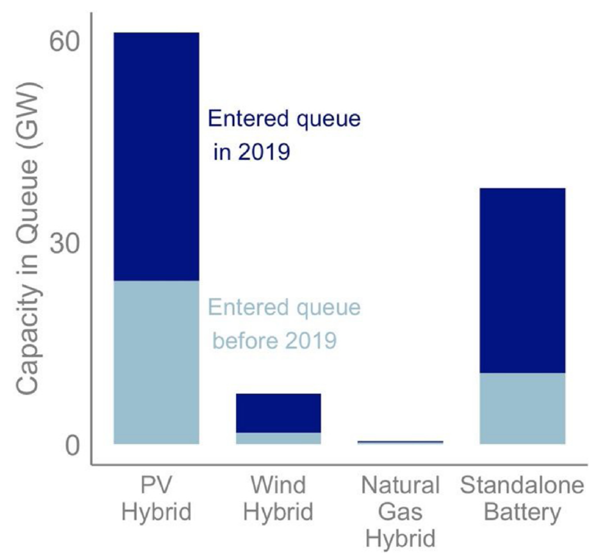

Fig. 6. Hybrid and standalone battery capacity in seven selected interconnection queues.

the standalone projects are sited in the same location as hybrid projects. In reality, standalone battery projects might be sited in a more congested pricing node than we use here, but such a siting optimization is outside the scope of this analysis. Overall, this analysis provides a first-cut historical estimation of hybrid market value relative to independently located wind, PV, and storage resources. It does not comprehensively assess value across all potential configurations or future wholesale market conditions.

We develop a rough bound on our market value estimates by using two different optimization algorithms to dispatch the batteries. Our high-value algorithm assumes perfect foresight of real-time electricity prices when determining optimal dispatch. Conversely, our low-value algorithm uses the optimal schedule from the previous day to set a target charge and discharge schedule for the battery during the operating day (Day-ahead Persistence method). The actual achieved charge and discharge schedule is then constrained by the operating day's actual wind/PV resource and limits on the battery. In both of these cases, we model an AC-coupled system and a 4 -h-duration battery with 81 % roundtrip efficiency that is sized to 50 % of the PV or wind nameplate capacity. These assumptions are informed by the review of the

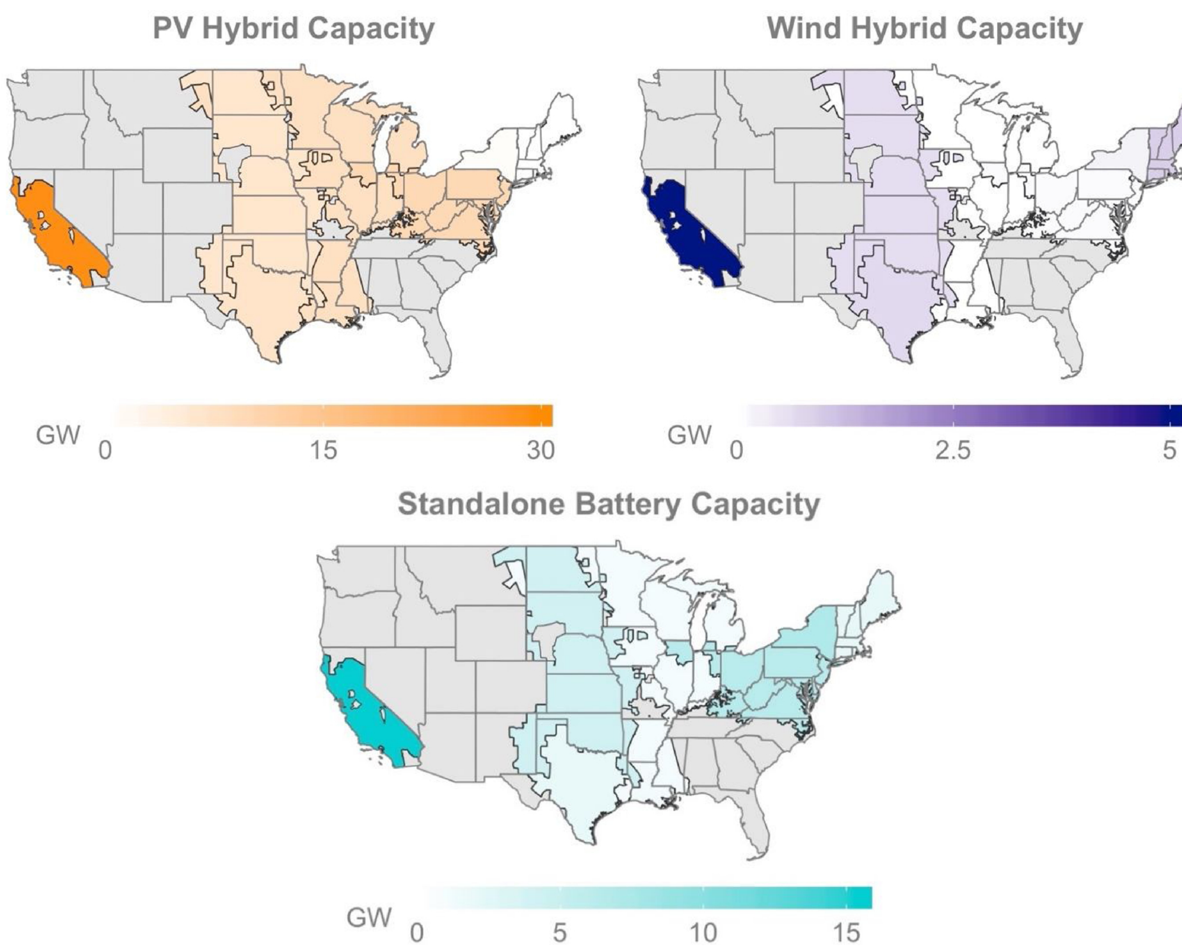

Fig. 7. Map of PV hybrid, wind hybrid, and standalone battery activity in seven ISO/RTO queues at the end of 2019.

Table 2
Percentage of PV and wind generators hybridizing in each ISO/RTO queue.

ISO/RTO	PV	Wind
CAISO	67 %	50 %
ERCOT	13 %	3%
SPP	22 %	1%
MISO	16 %	0%
PJM	17 %	0%
NYISO	5%	1%
ISO-NE	0%	6%

development pipeline presented in Section 3. We constrain the hybrid battery to charge only from the generator, not from the grid[10] and limit the maximum generation of the hybrid plant to the renewable generator's nameplate capacity.[11] We allow the standalone battery to charge from the grid exclusively at its nameplate capacity. Finally, projects in California earn capacity revenue based on a capacity credit for wind/PV defined by the California Public Utilities Commission, plus

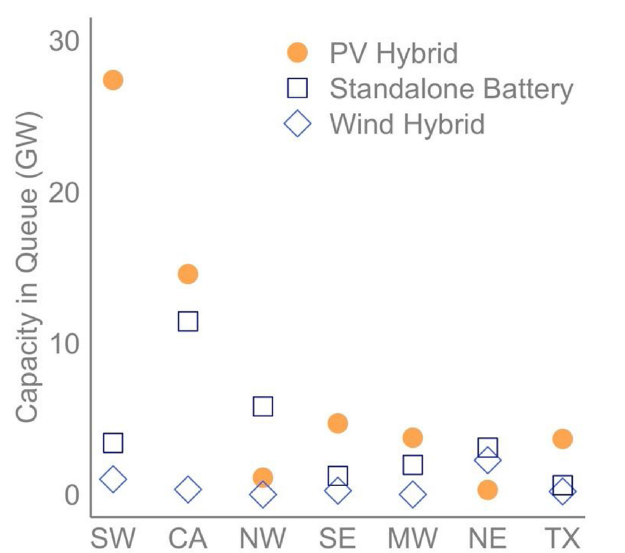

Fig. 8. Regional breakdown of U.S. hybrid and standalone battery projects at the end of 2018, based on ISO/RTO and additional utility queue data.
Note: Acronyms represent Southwest (SW), California (CA), Northwest (NW), Southeast (SE), Midwest (MW), Northeast (NE), and Texas (TX).

[10] The production tax credit (PTC), typically used by wind plants (in lieu of an ITC), cannot be applied to storage. Hybrid wind-battery plants that take the PTC would, as a result, not be constrained to charge from the wind plant. However, wind plants can and sometimes have taken the ITC (or an earlier cash grant), in which case such plants would seek to charge solely or primarily from the wind facility.

[11] The limit is driven by the capacity at the point of interconnection requested by the developer from a transmission operator. While this is a developer choice, rather than a fixed constraint, interconnection queue data suggests hybrid developers are sizing their POI limit close to the size of the renewable generator.

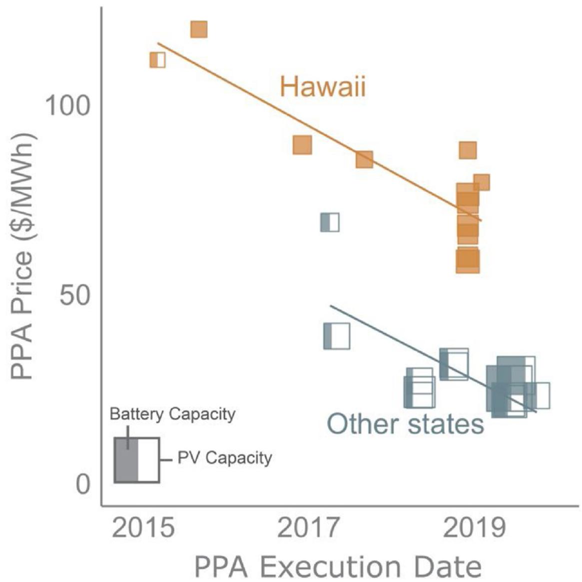

Fig. 9. Levelized price of PV-battery PPAs.
Note: Box sizes scale with total PV capacity and fully shaded boxes represent 1 to 1 PV-to-battery ratio.

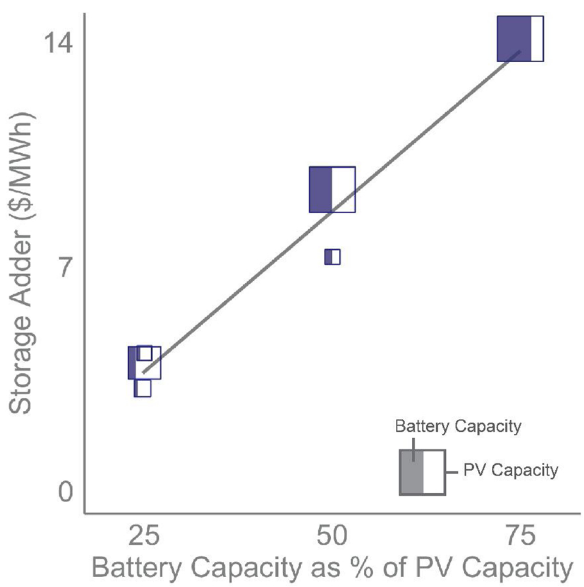

Fig. 10. Levelized battery adder as a function of battery-to-PV capacity, for PPAs with 4 h of battery storage.
Note: Box sizes scale with total PV capacity and fully shaded boxes represent 1 to 1 PV-to-battery ratio.

100 % of storage's nameplate capacity.[12]

Fig. 11 presents our results for wind and PV projects, expressed in levelized terms, where the revenues of each bar (i.e., standalone wind/PV and hybrid capacity and energy revenues) are divided by the total energy produced by the wind/PV system. Comparing the standalone generator to the hybrid bars shows the additional value of having onsite storage located with the wind and PV (i.e., storage only affects the hybrid bars). The top of each colored bar represents the high-value algorithm applied to hourly real-time prices. The gray bars represent the differences in summed energy and capacity values when using the Day-ahead Persistence method (low range) vs. the high value algorithm applied to a 15-minute real-time energy price time series (high range). The gray ranges are driven only by changes in energy values between the scenarios.

In the high-value case, there is a $29/MWh value premium for PV-hybrid projects as compared to PV-only projects in California. The value premium in Texas is significantly lower, at only $5/MWh. Comparing this premium to the approximately $10/MWh cost adder shown in Fig. 10 for a 50 % battery-to-PV ratio suggests that these projects would be more attractive in California than in Texas. In the low-value case, the premium is reduced to $16/MWh in California and $1/MWh in Texas. Currently, many researchers and industry leaders are implementing statistical models, dynamic programs, and model predictive control to improve forecasting and dispatching to capture as much of the perfect foresight value as possible (Carriere et al., 2020; Dorris, 2019; Jiang and Powell, 2015). Our wind results are similar to our PV results, with wind-hybrid premiums of $26/MWh in California and $7/MWh in Texas, in the high-value case. In the low-value case, the premium is $13/MWh in California and $3/MWh in Texas. The impact of dispatching storage against 15-minute prices instead of hourly average prices is modest, increasing the value premium by at most $2/MWh.

Although hybridization increases market value compared to standalone PV and wind generators, restricting the battery system to charge only from the co-located generator and limiting output by the renewable generator's interconnection limit decreases value compared to standalone generator and battery systems that are not so constrained. As a result, hybridizing storage with PV reduces total value by 7% in California and 11 % in Texas relative to the value of standalone storage and PV (Fig. 12).[13] For wind, the value reduction due to hybridization is 5% in California and less than 2% in Texas. These results rely on recent historical prices for energy and capacity services, and presume that standalone batteries would be sited in the same general vicinity as the solar/wind plants. They imply that benefits from reduced interconnection costs and the availability of the ITC would need to be greater than 2%–11 % to justify hybridizing; if these two cost synergies do not exceed these levels, then investors may prefer standalone plants.[14]

5. Wholesale market operational barriers and opportunities

Although hybrid projects are on the rise, their participation models (the way hybrids interface in U.S. electricity markets) are nascent. Participation models have already been mostly defined for the two components of hybrid projects—VREs and electric storage resources (ESRs)—for example, through Federal Energy Regulatory Commission (FERC) Order 841 and ISO/RTO stakeholder discussions. Understanding how these technologies independently participate in electricity markets informs potential participation models for hybrid resources. For instance, unique aspects of VREs and ESRs are typically captured through data and metering requirements, offer parameter information, and market-clearing software design.

All U.S. ISOs/RTOs use wind and solar generation forecasts for day-ahead and real-time timeframes. VREs are typically scheduled through the market clearing at the forecast amount given their $0 or negative energy offers, unless transmission congestion or very low load and minimum-generation constraints of other resources require the ISO/

[12] The hybrid capacity credit is limited by the generator nameplate capacity (e.g., when the capacity credit of standalone PV is greater than 50%, the capacity credit of the hybrid is limited to 100%).

[13] Fig. 12 uses high-value case results (i.e., hourly perfect foresight dispatch). If the low value case is used, the absolute difference is -$2.62 (California) and -$2.76 (Texas) for solar and -$3.6 (California) and -$0.68 (Texas) for wind.

[14] This 2-11% estimated value loss may understate the operational limitations of hybrids, in as much as our analysis assumes that the standalone battery would be located in the same vicinity as the wind/solar plants. In practice, standalone batteries would likely locate in constrained areas of the grid where their value is maximized.

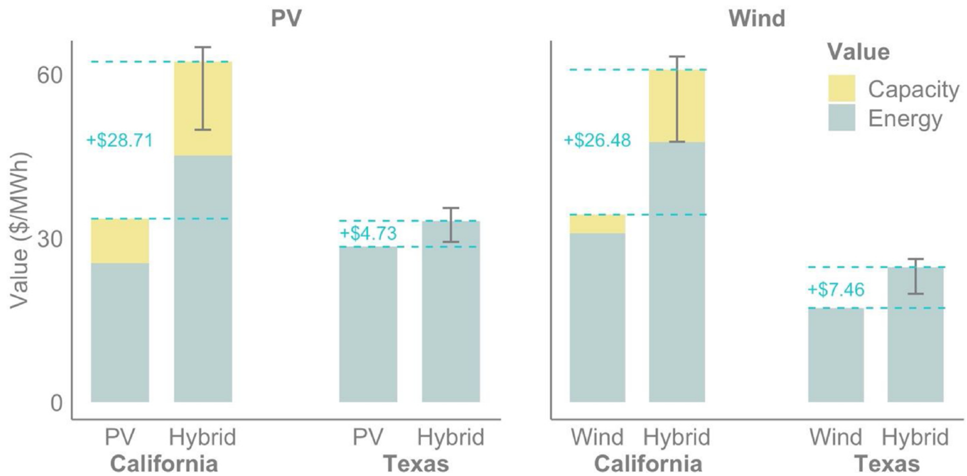

Fig. 11. Market value for PV and wind hybrid and standalone projects.

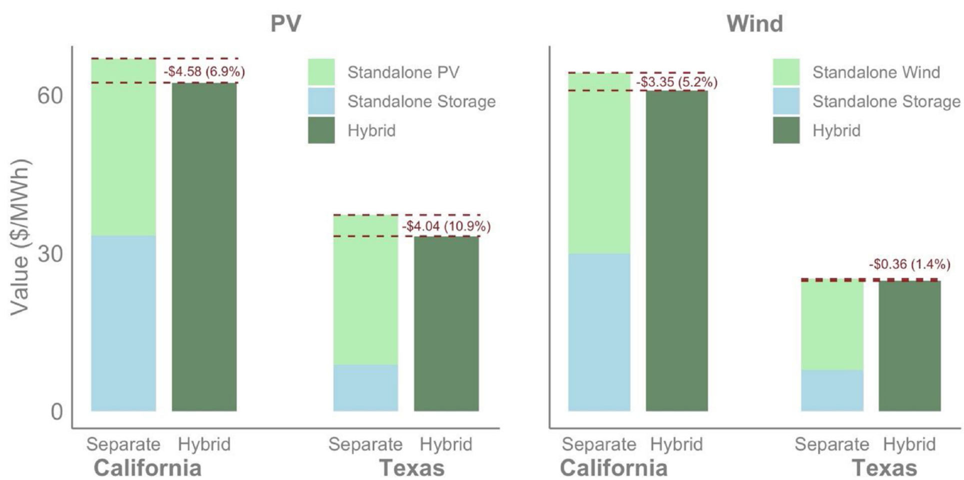

Fig. 12. Reduction in value from hybridizing relative to using separate generator and battery storage systems.

RTO to dispatch the VRE below the forecast amount (Ela and Edelson, 2012). Conversely, standalone ESRs submit offers from their maximum charging power to their maximum discharging power, but they are limited in their economic scheduling point by the amount of energy they have to provide as determined by their current state of charge (SOC) or the SOC for the market interval (Singhal and Ela, 2020, 2019).[15]

Hybrid projects increase the opportunities for and complexity of engaging in the market. Scheduling hybrids may require both forecasting VRE production and considering ESR SOC. Whether and how those requirements fall on the hybrid project or the ISO/RTO depends on the participation model.

The remainder of this section describes proposed hybrid participation models and the corresponding challenges to integrating hybrids in electricity markets. Although we focus on ISO/RTO regions, many similar questions arise in non-ISO/RTO regions of the United States.

5.1. Electricity market participation model options

Electricity market participation models vary with regard to responsibility and complexity (Fig. 13). The ISO/RTO interfaces (blue arrows)—which may include cost offers, telemetry, forecasts, and/or operating parameters—change based on the model employed. On the left side of the figure, hybrids are represented by their separate components. On the right, the market considers hybrid projects as a combined system.

Although we provide a few theoretical advantages and disadvantages of each model below, we do not recommend any option over another. In fact, if deemed reliable and cost-effective, it may be useful for ISOs/RTOs to allow all options so hybrid project owners with different goals and offering strategies can choose the models that best fit their objectives. We believe the range of participation models discussed here covers a broad set of options, but additional models likely will emerge. Note that this section focuses on the offer and scheduling options and does not cover other important features of market design, such as penalty design and market mitigation.

Separate Independent Resources Model (Fig. 13a): One way to engage hybrids in markets is to separately capture the unique characteristics of each constituent technology. This option requires minimal change to the existing market design, because models for independently managed VREs and ESRs already exist or are being developed. Offer, settlement, and mitigation rules likely require little modification from current practices. VRE dispatch is determined by forecasts, and penalties can be based on existing rules. ESRs can use FERC Order 841 compliant models including the use of SOC in determining whether schedules are feasible. This approach allows for enhanced reliability, because the ISO/RTO has complete information on anticipated production and any limitations. However, it may limit the flexibility for hybrid plant owners to develop bidding strategies that reflect unique

[15] ISOs/RTOs perform SOC management differently. Some use it directly, others not at all, and others for limiting in certain situations.

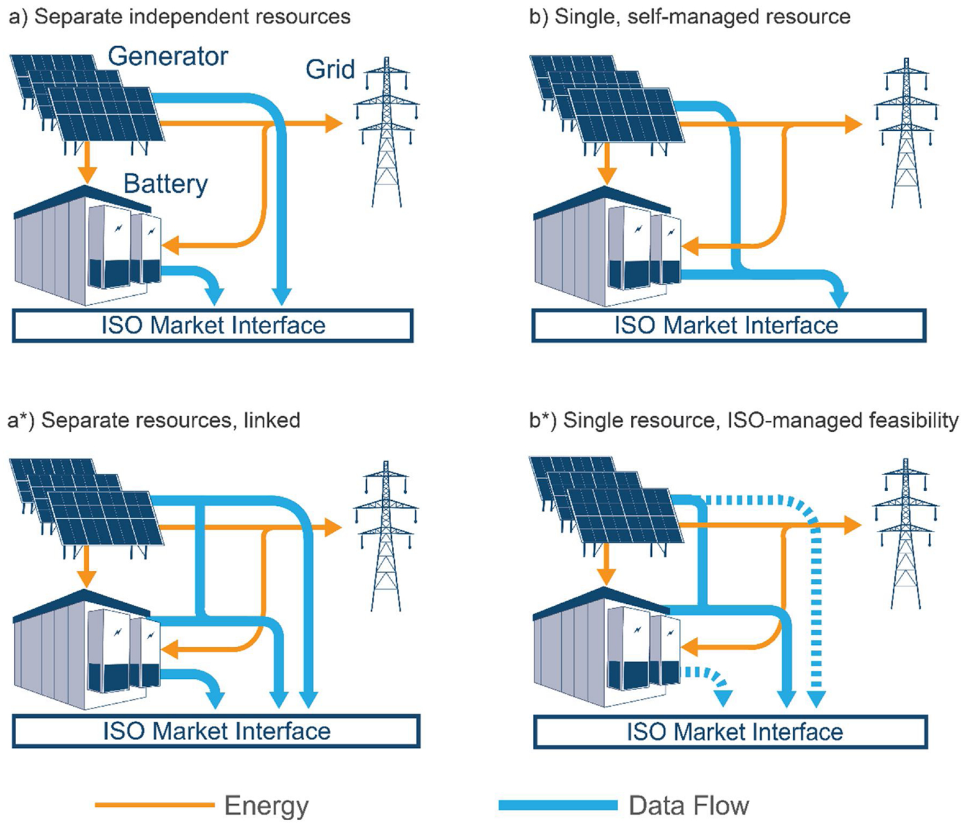

Fig. 13. Spectrum of participation models for hybrid resources.
Note: Dashed lines represent minimal interface with the ISO.

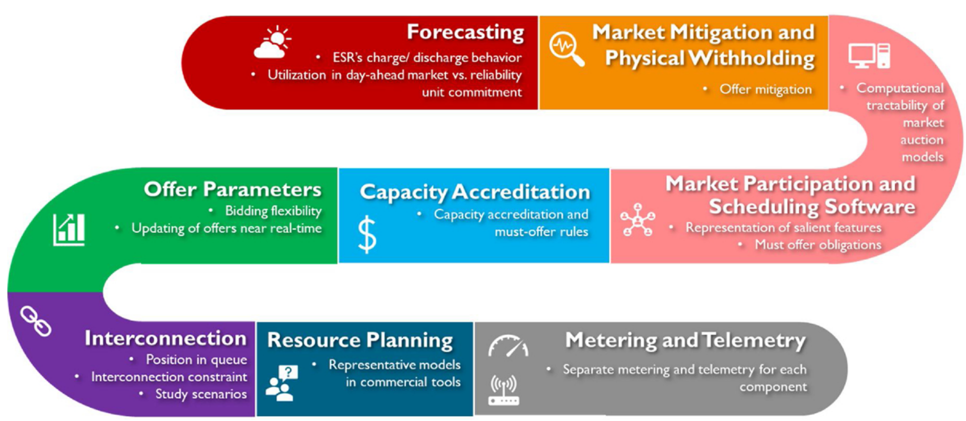

Fig. 14. Summary of key challenges to hybrid participation.

value opportunities for hybrid resources. For example, separate VRE and ESR offers may make it more difficult to meet ITC eligibility requirements mandating that storage charges primarily from the renewable generator.

Single, Self-Managed Resource Model (Fig. 13b): At the opposite bookend, the hybrid resource can be treated as a single integrated resource and allowed to self-manage its unique characteristics through a set of single resource offers and operating parameters. Offer capacity limits and bids can be used to ensure desired hybrid output from the asset's perspective. From the ISO/RTO perspective, this option is simple to implement and may be successful in avoiding computational issues with ESR SOC and VRE forecast management. Furthermore, it enables the participant to use internal capabilities that fully reflect the participant's knowledge of resource capabilities, thereby exploiting unique hybrid value opportunities. By treating the hybrid as a single integrated resource, many of the challenges associated with unique aspects of VREs and ESRs can be reduced, with performance risks shifted to the participant. However, issues regarding settlements, infeasible schedules, and mitigation rules (e.g., verifiable costs and withholding rules) may still need to be addressed. Finally, requiring the hybrid owner to be responsible for its feasible operation would mean the ISO/RTO may have limited to no visibility into the feasibility of scheduled energy or AS during critical periods.

Single Resource, ISO/RTO-Managed Feasibility Model (Fig. 13b*): This option involves modifications to the single integrated resource by providing additional features to prevent infeasible schedules. The hybrid asset owner can offer as a single resource and get scheduled as a single resource. However, the ISO/RTO may check the cleared schedule to ensure it can be met given VRE forecasts and SOC levels. As an example, the ISO/RTO can use telemetry and forecasts to prevent infeasible awards. The ISO/RTO may still need the same data and telemetry as the separate independent option to provide feasible schedules and maintain reliable operations, but it can otherwise allow the hybrid operator flexibility to develop a unique bidding strategy for the facility as a whole.

Separate Resources, Linked Model (Fig. 13a*): Another approach is to adjust the separate independent resources model to include an additional linking constraint. The linking constraint allows the hybrid resource to operate differently than how two independent resources would operate by, for example, limiting grid charging or charging otherwise clipped energy. In many ISOs/RTOs, combined-cycle configuration-based models adopt a similar approach, where each facility of the combined cycle is modeled separately but transition constraints and costs depend on the configuration of the entire plant. For hybrids, the linking constraint may simply be a plant minimum output. Each component can provide a minimum and maximum output (e.g., charge maximum to discharge maximum, zero to forecast), but a combined minimum and maximum is also provided (e.g., 0 to rating) to ensure eligibility for the ITC. Considering the operation of the hybrid and the individual components explicitly can make this option economically attractive for hybrid resource owners, because it can improve the ability of the ISO to produce an efficient schedule by capturing the hybrid's characteristics along with the characteristics and constraints of the power system. However, the linking constraint may increase complexity and market-clearing solution times.

5.2. Key challenges of hybrid resource participation

Hybrid resources pose new technical challenges that must be addressed to enhance participation in energy, AS, and capacity markets while clarifying the associated market efficiency and reliability implications. The challenges are summarized in Fig. 14 and discussed below.

5.2.1. Forecasting

Forecasts are needed to ensure reliable operations. VREs are treated differently in contemporary market structures. For instance, VREs are often not charged imbalance penalties given their limited controllability of production. It will be harder for the ISO/RTO to forecast a hybrid resource's output given the uncertainty around the ESR component's charge/discharge behavior; this may force the participant to opt for the separate independent resources model to avoid associated imbalance penalties for the VRE. Alternatively, the single, self-managed resource model allows the participant to self-provide forecasts; however, the hybrid resource is likely to be levied with imbalance penalties given the capabilities of the ESR component. There is uncertainty around potential bidding opportunities in day-ahead markets, use of self-provided forecasts in reliability unit commitments, and readjustment of forecasts near real time.

5.2.2. Market mitigation and physical withholding

Contemporary market power mitigation rules were developed for traditional resources and are based on fuel costs; rules are currently being developed for standalone ESRs with costs based on opportunity costs. The same goes for hybrid resources, but with added complexity. There is uncertainty around how offers should be mitigated and which resource component incurs the costs, for example, when the ESR charges from the VRE instead of the grid.

5.2.3. Market participation and scheduling software

A primary challenge for hybrid resources is appropriately representing their unique physical and operating characteristics, such as SOC and coupling-strategy-dependent constraints, within conventional security-constrained unit-commitment and economic-dispatch models. There may be a need for a dedicated hybrid resource participation model that appropriately accounts for salient hybrid features and consecutively improves economic and reliable operations. Section 5.1 describes a range of model options. Note that accurate representation of salient features is likely to impact the computational tractability of market auction models, analogous to combined-cycle gas turbine modeling.

5.2.4. Capacity accreditation

Capacity accreditation rules may need modification. ISOs/RTOs are still modifying rules for ESRs. Each ISO/RTO values ESRs differently based on the ESR's continuous-discharge duration (e.g., 2–10 continuous hours). Hybrid projects have a different capacity contribution from standalone ESRs and thus need further evaluation. Furthermore, there is uncertainty regarding must-offer rules for capacity resources; for example, should each individual component be required to offer into the energy markets and, if so, for all hours?

5.2.5. Offer parameters

Traditional market structures do not allow offers to be updated after the market closes given the existing computational capabilities; however, hybrid owners will need to update their offers near real time owing to the individual resource characteristics. One option is to treat hybrids like VREs, allowing for automatic updates of power quantities, but the challenge with updating offer prices still remains. Thus, there is a need for enhanced bidding flexibility apart from the decision about what offer parameters are needed. FERC Order 841 lists a set of 13 offer parameters for ESRs that may also apply to hybrids.

5.2.6. Interconnection

FERC Order 845 has reduced barriers to interconnection by streamlining the process and allowing new interconnection services at levels below the facility's nameplate capacity, which can help avoid costly and unnecessary transmission system upgrades. Additionally, a surplus interconnection agreement will permit fast-track interconnection of new facilities with existing generators that do not use their full capacity at all times. For example, adding a 25-MW battery to an existing 50-MW solar facility no longer requires studies of 75-MW injections but can be studied as the original 50-MW capacity, as long as that injection will not be exceeded, without bringing the expanded project back into the queue process. This may enable proliferation of hybrid resources going forward. However, there is uncertainty around how new hybrid interconnections will be treated in ISOs/RTOs. The addition of ESRs to existing VRE projects in interconnection queues may result in the VRE losing its position in the queue. Interconnection studies might need to incorporate numerous additional scenarios, such as participation models, configurations, and loading conditions. Hybrids may not be allowed to obtain a single interconnection service if the ISO/RTO decides to model the components as separate independent resources, potentially increasing the interconnection study time through, for example, load interconnection studies when the ESR charges from the grid (Gramlich et al., 2019).

5.2.7. Resource planning

Resource plans are conducted either through a combination of integrated resource plans (IRP) by individual utilities, or through capacity market outcomes. IRPs are often computed through a capacity-expansion modeling framework, where the optimal resource mix is determined through the software to meet anticipated load requirements, as well as other reliability and policy targets. Operational simulation tools (i.e., production-cost models) are also used to evaluate operational and production-cost impacts on future systems given a number of different scenarios. Neither of these commercial tools generally have standard representative models for hybrid resources. Such models are needed to clarify hybrid contributions to grid systems.

5.2.8. Metering and telemetry

There may be a need for two separate meters and separate telemetry for each component within a hybrid resource.

6. Conclusions and open research questions

Commercial interest in the generator-battery hybrid model is growing rapidly, with signed PPAs and interconnection queues demonstrating major expansion of hybrid projects over the next several years. Time will tell whether this trend is a short-lived product of current policy drivers or a more lasting phenomenon. We show, using historical prices for energy and capacity services, that co-locating batteries with VREs offers a significant potential value premium in wholesale markets. However, independently sited batteries without limitations on grid charging or renewable generator interconnection limits can capture more value, suggesting that cost-reduction synergies due to co-location will need to exceed the potential revenue loss due to hybridization.

More research is needed to clarify the long-term cost-reduction potential, market value, and risks/benefits of hybrid projects within the electricity system. First, research is needed to understand the total cost savings, if any, of hybrids vs. standalone projects. Second, there is a need to understand and predict hybrid operation to maximize value under evolving market designs. We present a simple optimization algorithm for managing a battery's SOC to maximize market value assuming perfect foresight. However, more sophisticated techniques are needed to find optimal bidding strategies under uncertainty for hybrid participation in wholesale markets and to show how this value evolves with increasing penetration of VREs and/or hybrids. This effort would be complemented by research on market participation issues and options beyond what we outline in Section 5. Third, research should evaluate the potential synergies of hybrid designs beyond the battery hybrids discussed in this article, including pairing multiple generation technologies with each other and using other forms of energy storage. Finally, hybrid resources should be incorporated accurately into long-term capacity-expansion models that are used for utility IRPs and regional policy studies.

CRediT authorship contribution statement

Will Gorman: Conceptualization, Methodology, Software, Data curation, Formal analysis, Visualization, Writing - original draft, Writing - review & editing. **Andrew Mills:** Supervision, Funding acquisition, Conceptualization, Methodology, Software, Writing - review & editing. **Mark Bolinger:** Data curation, Writing - review & editing. **Ryan Wiser:** Conceptualization, Writing - review & editing. **Nikita G. Singhal:** Writing - original draft. **Erik Ela:** Writing - original draft, Writing - review & editing. **Eric O'Shaughnessy:** Visualization.

Declaration of Competing Interest

The authors declare no competing interests.

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Appendix A

Tables A1–A3

Table A1
Battery Storage Technology Key for Table.A2

Acronym	Type
LIB	Lithium-ion
NAB	Sodium-based
PBB	Lead-acid

Table A2
Currently Online Hybrid Projects.

State	Project name	Paired Generator Technology	Battery Online Date	Generator Online Date	Capacity (MW-AC)		Battery Storage			Battery to Gen Ratio	Levelized PPA Price 2018 $/MWh
					Gen	Batt	Hr	MWh	Tech		
AL	Redstone Arsenal	Solar	Dec-2017	Dec-2017	10.0	1.0	2.0	2.0	LIB	10 %	#N/A
AR	Noland Wastewater Treatment Plant	Solar	Jul-2019	Jul-2019	5	6.0	2.0	12.0	#N/A	120 %	#N/A
AR	Westside Wastewater Treatment Plant	Solar	Jul-2019	Jul-2019	5	6.0	2.0	12.0	#N/A	120 %	#N/A
AZ	Pinal Central Energy Center	Solar	Apr-2018	Apr-2018	20.0	10.0	4.0	40.0	LIB	50 %	$68.90
AZ	Wilmot	Solar	Dec-2019	Dec-2019	100.0	30.0	4.0	120.0	#N/A	30 %	$40.70
CA	Genentech-Oceanside	Solar	Apr-2016	Apr-2016	4.5	2.0	1.0	2.0	LIB	44 %	#N/A
CA	Beacon BESS 1	Solar	Oct-2018	Dec-2017	37.8	20.0	0.5	10.0	LIB	53 %	#N/A
CA	UC Merced Solar	Solar	Dec-2018	Dec-2018	4.5	0.5	1.8	0.9	LIB	11 %	#N/A
CO	Panasonic Carport Solar	Solar	Aug-2017	May-2017	1.3	1.0	2.2	2.2	LIB	77 %	#N/A
CT	CMEEC - Norwich Stott St Solar	Solar	Dec-2016	Dec-2016	3.5	0.8	3.8	3.0	LIB	23 %	#N/A
CT	CMEEC - Polaris Park Solar	Solar	Aug-2017	Aug-2017	3.5	0.8	4.1	3.3	LIB	23 %	#N/A
FL	Babcock Solar Energy Center	Solar	Mar-2018	Dec-2016	74.5	10.0	4.0	40.0	LIB	13 %	#N/A

(continued on next page)

Table A2 (*continued*)

State	Project name	Paired Generator Technology	Battery Online Date	Generator Online Date	Capacity (MW-AC)		Battery Storage			Battery to Gen Ratio	Levelized PPA Price 2018 $/MWh
					Gen	Batt	Hr	MWh	Tech		
FL	Citrus Solar Energy Center	Solar	Mar-2018	Dec-2016	74.5	4.0	4.0	16.0	LIB	5%	#N/A
HI	KRS I Anahola Solar	Solar	Aug-2015	Aug-2015	12.0	6.0	0.8	4.6	LIB	50 %	#N/A
HI	KIUC Kapaia PV and BA Storage Project	Solar	May-2017	May-2017	15.0	13.0	2.1	27.5	LIB	87 %	$119.80
HI	AES LAWAI SOLAR	Solar	Dec-2018	Dec-2018	20.0	20.0	5.0	100.0	LIB	100 %	$89.40
HI	Kekaha	Solar	Sep-2019	Sep-2019	14.0	14.0	5.0	70.0	#N/A	100 %	$85.50
HI	West Loch Solar One	Solar	Oct-2019	Oct-2019	20	20.0	4.0	80.0	#N/A	100 %	#N/A
LA	New Orleans Solar Power Plant	Solar	Jun-2016	Jun-2016	1.1	0.5	1.0	0.5	LIB	45 %	#N/A
MA	Hampshire College	Solar	May-2017	May-2017	3.4	1.0	1.0	1.0	LIB	29 %	#N/A
MA	MA Solar Storage 1	Solar	Apr-2018	Mar-2018	1.1	1.0	2.0	2.0	LIB	91 %	#N/A
MN	Anoka BESS	Solar	Dec-2018	Oct-2018	3.4	6.0	2.0	12.0	LIB	176 %	#N/A
MN	Athens BESS	Solar	Dec-2018	Dec-2018	6.6	6.0	2.0	12.0	LIB	91 %	#N/A
NJ	Hopewell Valley High School	Solar	Dec-2015	Dec-2015	0.9	1.0	1.0	1.0	LIB	111 %	#N/A
NM	Prosperity Energy Storage Facility	Solar	Sep-2011	Sep-2011	0.5	0.8	1.6	1.3	PBB	160 %	#N/A
NM	Los Alamos PV Site	Solar	Sep-2012	Sep-2012	1.0	1.8	4.6	8.3	NAB	180 %	#N/A
SC	MCRD Parris Island PV	Solar	Dec-2018	Oct-2018	6.0	4.0	1.0	4.0	LIB	67 %	#N/A
TX	OCI Alamo Solar I	Solar	Aug-2016	Dec-2013	40.7	1.0	0.3	0.3	LIB	2%	#N/A
TX	Castle Gap	Solar	Jun-2019	Dec-2019	180.0	10.0	4.2	42.0	#N/A	6%	#N/A
VT	Stafford Hill Solar	Solar	Sep-2015	Mar-2015	2.0	2.0	1.7	3.4	LIB	100 %	#N/A
VT	GMP -Milton	Solar	Dec-2019	Dec-2019	5	2.0	4.0	8.0	#N/A	40 %	#N/A
VT	GMP -Ferrisburgh	Solar	Dec-2019	Dec-2019	5	2.0	4.0	8.0	#N/A	40 %	#N/A
VT	GMP-Essex	Solar	Dec-2019	Dec-2019	4.5	2.0	4.0	8.0	#N/A	44 %	#N/A
HI	Kaheawa Wind Power II LLC	Wind	Jun-2012	Jun-2012	21.0	10.0	2.0	20.0	LIB	48 %	#N/A
HI	Auwahi Wind Energy	Wind	Dec-2012	Dec-2012	24.0	11.0	0.4	4.4	LIB	46 %	#N/A
IL	Grand Ridge Battery Projects	Wind	Dec-2013	Oct-2008	210.0	33.0	0.4	13.5	LIB	16 %	#N/A
IL	FPL Energy Illinois Wind LLC	Wind	Nov-2014	Dec-2009	217.5	20.0	0.4	8.3	LIB	9%	#N/A
NM	Casa Mesa Wind Energy Center	Wind	Nov-2018	Nov-2018	50.9	1.0	12.6	12.6	LIB	2%	#N/A
PA	Meyersdale Windpower Battery	Wind	Dec-2015	Dec-2003	30.0	18.0	1.0	18.0	LIB	60 %	#N/A
SD	Rolling Thunder Wind Farm	Wind	Nov-2018	Nov-2009	25.0	0.8	1.0	0.8	LIB	3%	#N/A
TX	Notrees Windpower	Wind	Dec-2012	Apr-2009	152.5	36.0	0.4	13.6	LIB	24 %	#N/A
TX	NRG Elbow Creek Energy Storage Project	Wind	Nov-2017	Dec-2008	121.9	2.0	0.4	0.7	LIB	2%	#N/A
TX	Pyron Wind Farm LLC	Wind	Jan-2018	Feb-2009	249.0	9.9	1.0	9.9	LIB	4%	#N/A
TX	Inadale Wind Farm LLC	Wind	Jan-2018	Sep-2009	197.0	9.9	1.0	9.9	LIB	5%	#N/A
WV	Laurel Mountain	Wind	Oct-2011	Aug-2011	97.6	16.0	1.0	16.0	LIB	16 %	#N/A
WV	Beech Ridge Energy Storage	Wind	Oct-2015	Jan-2010	100.5	31.5	0.4	12.5	LIB	31 %	#N/A
AK	Kodiak Island	Hydro	Jul-2009	Sep-2012	33.8	3	0.7	2	NAB	9%	#N/A
AK	Cordova	Hydro	Jun-1991	Jun-2019	7.3	1.0	1.0	1.0	LIB	14 %	#N/A
VA	Buck	Hydro	Jan-1912	Mar-2018	8.5	4.0	1.0	4.0	LIB	47 %	#N/A
VA	Byllesby	Hydro	Jan-1912	Mar-2018	21.6	4.0	1.0	4.0	LIB	19 %	#N/A
CA	Santa Rita Jail	Nat Gas	Jul-2012	Jan-2017	1.4	2.0	2.0	4.0	LIB	143 %	#N/A
CA	El Centro	Nat Gas CC	Oct-2016	Aug-1952	358.3	30.0	0.7	20.0	LIB	8%	#N/A
CA	Grapeland Peaker	Nat Gas CT	Dec-2016	Sep-2007	49.8	10.0	1.0	10.0	LIB	20 %	#N/A
CA	Center Peaker	Nat Gas CT	Apr-2017	Sep-2007	49.8	10.0	1.0	10.0	LIB	20 %	#N/A
IN	Harding Street	Nat Gas ST	Jun-2016	Jun-1958	1,044.7	20.0	1.0	20.0	LIB	2%	#N/A
AK	Kotzebue	Oil	Dec-2015	Dec-1992	11.8	1.2	0.8	1.0	LIB	10 %	#N/A
CA	Pebbly Beach	Oil	Aug-2012	Jul-1966	11.7	1.0	6.8	6.8	NAB	9%	#N/A
HI	Palaau Power	Oil	May-2017	Apr-1982	15.1	2.0	1.0	2.0	#N/A	13 %	#N/A
ME	William F Wyman	Oil	Dec-2016	Jan-1957	846.0	16.7	0.7	10.9	LIB	2%	#N/A
NC	Ocracoke	Oil	Jan-2017	Apr-1991	3.0	1.0	1.0	1.0	LIB	33 %	#N/A

Table A3
Proposed and Announced Hybrid Projects.

State	Project name	Paired Generator Technology	Battery Online Date	Generator Online Date	Capacity (MW-AC)		Battery Storage		Battery to Gen Ratio	Levelized PPA Price 2018 $/MWh
					Generator	Battery	Hr	MWh		
CA	Alamitos Energy Center	Natural Gas	Jan-2021	Apr-2020	1,093.0	100.0	4.0	400.0	9%	#N/A
CA	Stanton Energy Reliability Center	Natural Gas	Jan-2020	Jan-2020	181.5	10.0	#N/A	#N/A	6%	#N/A
NY	Ravenswood	Natural Gas	Mar-2021	Jan-2023	1,000.8	316.0	#N/A	#N/A	32 %	#N/A
MD	Montgomery County Microgrid	Natural Gas/Solar	Aug-2021	Aug-2021	7.5	0.3	#N/A	#N/A	3%	#N/A
MD	Prince Georges County Microgrid	Natural Gas/Solar	Aug-2022	Aug-2022	6.8	1.6	#N/A	#N/A	24 %	#N/A
AR	Searcy Solar	Solar	Jan-2021	Jan-2021	100.0	30.0	#N/A	#N/A	30 %	#N/A
AZ	Maricopa County Battery Storage Project	Solar	Dec-2021	Dec-2021	65.0	50.0	2.7	135.0	77 %	#N/A
AZ	Sonoran Energy Center	Solar	Jun-2023	Jun-2023	250.0	250.0	4.0	1,000.0	100 %	#N/A
AZ	Storey Energy Center	Solar	Jun-2023	Jun-2023	88.0	88.0	4.0	352.0	100 %	#N/A
AZ	Wilmot Energy Center	Solar	Dec-2020	Dec-2020	100.0	30.0	#N/A	#N/A	30 %	#N/A
AZ	Yuma Solar Energy Project	Solar	Dec-2020	Dec-2020	110.0	100.0	#N/A	#N/A	91 %	#N/A
CA	Big Beau Solar + Storage Project	Solar	Dec-2021	Dec-2021	128.0	40.0	4.0	160.0	31 %	≤30.9
CA	Desert Harvest Solar Project	Solar	Dec-2020	Jan-2020	70.0	35.0	4.0	140.0	50 %	LMP plus $15.25
CA	Eland Solar Farm	Solar	Apr-2023	Apr-2023	400.0	300.0	4.0	1,200.0	75 %	$28.50
CA	RE Mustang Solar	Solar	Dec-2020	Dec-2020	150.0	45.0	4.0	180.0	30 %	≤31.8
CA	Sonoran West Solar Electric Generating System	Solar	Mar-2020	Mar-2020	350.0	350.0	#N/A	#N/A	100 %	#N/A
CA	Sonrisa Solar Park	Solar	Dec-2022	Dec-2022	200.0	40.0	4.0	160.0	20 %	#N/A
CO	Hartsel Solar Center Project	Solar	Dec-2020	Dec-2020	34.0	68.0	#N/A	#N/A	200 %	#N/A
FL	Osceola County Solar I	Solar	Dec-2022	Dec-2022	74.5	5.0	#N/A	#N/A	7%	#N/A
FL	Osceola County Solar II	Solar	Dec-2023	Dec-2023	74.5	5.0	#N/A	#N/A	7%	#N/A
FL	Manatee	Solar	Dec-2021	Dec-2016	74.5	409.0	2.2	900.0	549 %	#N/A
GA	Cedartown PV1	Solar	Jun-2021	Jun-2021	15.0	15.0	#N/A	#N/A	100 %	#N/A
GA	Screven PV1	Solar	Jun-2021	Jun-2021	5.0	5.0	#N/A	#N/A	100 %	#N/A
GA	Turkey Run Solar	Solar	Nov-2021	Nov-2021	195.5	40.0	0.1	2.0	20 %	#N/A
GA	Broken Spoke	Solar	Dec-2021	Dec-2021	195.5	40.0	2.0	80.0	20 %	#N/A
HI	AES Solar West Oahu	Solar	Mar-2020	Mar-2020	12.5	12.5	4.0	50.0	100 %	$79.50
HI	Energy Molokai	Solar	Mar-2020	Mar-2020	2.7	3.0	5.0	15.0	109%	#N/A
HI	Hale Kuawehi Solar	Solar	Dec-2022	Dec-2022	30.0	30.0	4.0	120.0	100 %	$65.80
HI	Hoohana Solar	Solar	Dec-2022	Dec-2022	52.0	52.0	4.0	208.0	100 %	$76.30
HI	Kuihelani Solar	Solar	Dec-2022	Dec-2022	60.0	60.0	4.0	240.0	100 %	$58.50
HI	Mililani I Solar	Solar	Dec-2022	Dec-2022	39.0	39.0	4.0	156.0	100 %	$68.00
HI	Pacific Missile Range Facility	Solar	Dec-2020	Dec-2020	44.0	44.0	#N/A	#N/A	100 %	#N/A
HI	Paeahu Solar	Solar	Dec-2022	Dec-2022	15.0	15.0	4.0	60.0	100 %	$87.90
HI	Waiawa Solar	Solar	Dec-2022	Dec-2022	36.0	36.0	4.0	144.0	100 %	$74.00
HI	Waikoloa Solar	Solar	Dec-2022	Dec-2022	30.0	30.0	4.0	120.0	100 %	$59.80
IN	Camp Atterbury Project	Solar	Jul-2020	Jul-2020	2.0	5.0	1.0	5.0	250 %	#N/A
MA	38 Happy Hollow Road Winchendon	Solar	Jan-2020	Jan-2020	5.0	3.3	#N/A	#N/A	66 %	#N/A
MA	Syncarpha Blandford	Solar	Apr-2020	Apr-2020	5.0	3.5	1.0	3.5	70 %	#N/A
MA	Syncarpha Halifax	Solar	Aug-2020	Aug-2020	1.7	2.0	1.0	2.0	120 %	#N/A
MA	Syncarpha Leicester	Solar	Mar-2020	Mar-2020	2.6	1.9	1.0	1.9	73%	#N/A
MA	Syncarpha Millbury	Solar	Apr-2020	Apr-2020	5.0	3.8	1.0	3.8	76%	#N/A
MA	Syncarpha Northampton	Solar	Apr-2020	Apr-2020	2.9	2.0	1.0	2.0	69%	#N/A
MA	Syncarpha Northbridge I	Solar	Apr-2020	Apr-2020	5.0	4.0	#N/A	#N/A	80 %	#N/A
MA	Syncarpha Northbridge II	Solar	Apr-2020	Apr-2020	5.0	3.0	#N/A	#N/A	60 %	#N/A
MA	Syncarpha Puddon 1	Solar	Mar-2020	Mar-2020	5.0	4.0	#N/A	#N/A	80 %	#N/A
MA	Syncarpha Puddon II	Solar	Apr-2020	Apr-2020	5.0	4.0	#N/A	#N/A	80 %	#N/A
MA	Syncarpha Tewksbury	Solar	Aug-2020	Aug-2020	4.2	1.0	#N/A	#N/A	24 %	#N/A
MA	Syncarpha Westminster	Solar	Apr-2020	Apr-2020	4.1	2.9	#N/A	#N/A	70 %	#N/A
MO	Green City Solar Plus Storage	Solar	Dec-2020	Dec-2020	10.0	2.5	#N/A	#N/A	25 %	#N/A
MO	Richwoods Solar Plus Storage	Solar	Dec-2020	Dec-2020	10.0	4.0	#N/A	#N/A	40 %	#N/A
MO	Utica Solar Plus Storage	Solar	Dec-2020	Dec-2020	10.0	2.0	#N/A	#N/A	20 %	#N/A
NC	Hot Springs Microgrid Solar & Battery Storage Facility	Solar	Jan-2020	Jan-2020	2.0	4.0	1.1	4.4	200 %	#N/A
NJ	Highland Park	Solar	Jan-2020	Jan-2020	1.1	2.0	1.0	2.0	182%	#N/A
NM	Arroyo Solar Energy Storage Hybrid	Solar	Jun-2022	Jun-2022	300.0	40.0	1.0	40.0	13 %	#N/A
NM	Angel Fire	Solar	?	?	6.0	3.0	4.0	12.0	50 %	#N/A
NM	Taos Mesa	Solar	?	?	15.0	12.0	4.0	48.0	80 %	#N/A
NV	Arrow Canyon Solar	Solar	Dec-2021	Dec-2021	400.0	150.0	5.0	750.0	38 %	$21.80
NV	Battle Mountain Solar	Solar	Dec-2021	Dec-2021	101.0	25.0	4.0	100.0	25 %	$22.30
NV	Dodge Flat Solar	Solar	Dec-2020	Dec-2020	200.0	50.0	4.0	200.0	25 %	$23.10
NV	Fish Springs Ranch PV 1 Solar Project	Solar	Dec-2020	Dec-2020	200.0	50.0	4.0	200.0	25 %	$25.90
NV	Gemini Solar & Battery Storage Project	Solar	Jan-2023	Jan-2023	690.0	380.0	3.7	1,400.0	55%	$25.10
NV	Southern Bighorn Solar & Storage Center	Solar	Jan-2023	Jan-2023	300.0	135.0	4.0	540.0	45 %	$21.90

(*continued on next page*)

Table A3 (*continued*)

State	Project name	Paired Generator Technology	Battery Online Date	Generator Online Date	Capacity (MW-AC)		Battery Storage		Battery to Gen Ratio	Levelized PPA Price 2018 $/MWh
					Generator	Battery	Hr	MWh		
NV	Townsite Solar Project	Solar	Dec-2021	Dec-2021	180.0	90.0	4.0	360.0	50 %	#N/A
NY	Community Solar (JFK Arpt)	Solar	Jan-2025	Jan-2025	13.0	7.5	#N/A	#N/A	58 %	#N/A
NY	NY13 Solar	Solar	Jan-2023	Jan-2023	19.9	4.0	#N/A	#N/A	20 %	#N/A
NY	NY16 Solar	Solar	Jan-2023	Jan-2023	19.9	4.0	#N/A	#N/A	20 %	#N/A
NY	NY37 Solar	Solar	Jan-2023	Jan-2023	19.9	4.0	#N/A	#N/A	20 %	#N/A
NY	Ridge View Solar Energy Center	Solar	Dec-2025	Dec-2024	350.0	100.0	4.0	400.0	29 %	#N/A
NY	JFK Airport	Solar	?	?	13.0	7.5	#N/A	#N/A	58 %	#N/A
PA	Caln Township Solar	Solar	Aug-2020	Aug-2020	4.3	4.3	#N/A	#N/A	100 %	#N/A
TX	Angus Solar & Storage	Solar	Aug-2020	Aug-2020	113.0	63.0	#N/A	#N/A	56 %	#N/A
TX	Eunice Solar & Storage	Solar	Dec-2020	Dec-2020	403.8	40.3	#N/A	#N/A	10 %	#N/A
TX	Galloway Solar & Storage	Solar	Dec-2021	Dec-2021	110.0	110.0	#N/A	#N/A	100 %	#N/A
TX	Luminant Castle Gap	Solar	Jun-2020	May-2021	65.0	25.0	#N/A	#N/A	38 %	#N/A
TX	Millhouse Solar and Storage	Solar	Dec-2020	Dec-2020	75.0	38.0	#N/A	#N/A	51 %	#N/A
TX	Queen Solar	Solar	Oct-2020	Dec-2019	400.0	50.0	#N/A	#N/A	13 %	#N/A
TX	Stillwater Solar & Storage	Solar	Aug-2020	Aug-2020	144.0	144.0	#N/A	#N/A	100 %	#N/A
TX	Permian Energy Center	Solar	Jul-2021	Jul-2021	420.0	40.0	1.0	40.0	10 %	#N/A
WA	Arlington Microgrid Project	Solar	Dec-2020	Feb-2020	0.5	0.5	#N/A	#N/A	100 %	#N/A
WI	Paris Solar Farm	Solar	Dec-2021	Dec-2021	200.0	50.0	#N/A	#N/A	25 %	#N/A
OH	Hardin Wind Energy Center	Solar/Wind	Jun-2020	Jun-2020	620.0	60.0	#N/A	#N/A	10 %	#N/A
OK	Skeleton Creek Energy Center	Solar/Wind	Dec-2023	Dec-2023	500.0	200.0	4.0	800.0	40 %	#N/A
OR	Wheatridge Wind Energy Facility	Solar/Wind	May-2023	Dec-2023	600.0	30.0	#N/A	#N/A	5%	#N/A
MA	Revolution Wind Farm (Offshore)	Wind	Dec-2023	Dec-2023	700.0	40.0	#N/A	#N/A	6%	#N/A
MT	Beaver Creek Wind I	Wind	Jun-2020	Mar-2020	960.0	120.0	#N/A	#N/A	13 %	#N/A
NY	Bluestone Wind	Wind	Dec-2020	Dec-2020	125.0	10.0	#N/A	#N/A	8%	#N/A
NY	Orsted South Fork	Wind	Dec-2022	Dec-2022	552.0	30.0	#N/A	#N/A	5%	#N/A
TX	High Lonesome W	Wind	Oct-2020	Dec-2019	500.1	50.0	#N/A	#N/A	10 %	#N/A

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