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Keep It Short

Exploring the Impacts of Configuration Choices on the Recent Economics of Solar-Plus-Battery and Wind-Plus-Battery Hybrid Energy Plants

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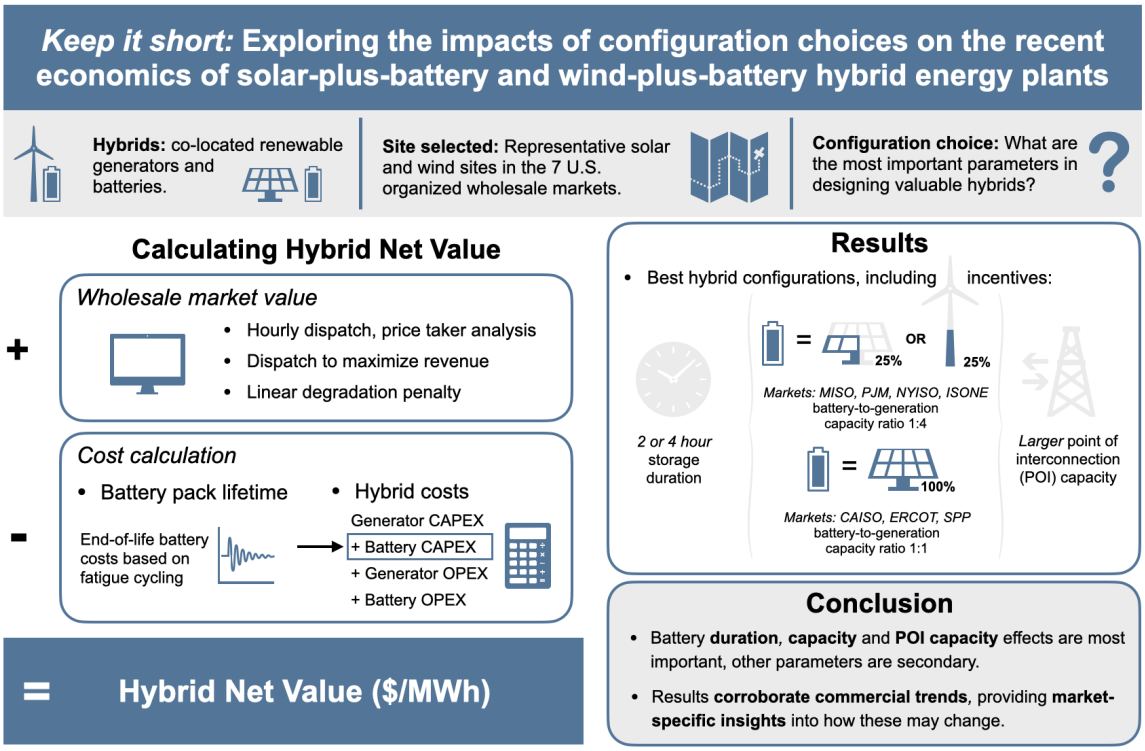
Acronyms and Abbreviations

AC	Alternating Current
AS	Ancillary Services
BOS	Balance of System
CAISO	California Independent System Operator
DC	Direct Current
DOD	Depth of Discharge
EOL	End of Life
ERCOT	Electric Reliability Council of Texas
ILR	Inverter Loading Ratio
ISO-NE	New England Independent System Operator
ITC	Investment Tax Credit
LFP	Lithium Iron Phosphate
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
O&M	Operations and Maintenance
PJM	PJM Interconnection
POI	Point of Interconnection
PTC	Production Tax Credit
PV	Photovoltaic
RCA	Rainflow Counting Algorithm
SOC	State of Charge
SPP	Southwest Power Pool
VRE	Variable Renewable Energy

Abstract

Commercial interest in renewable-battery hybrid power plants connected to the bulk power system ("hybrids") is rapidly growing in the United States and globally. Since hybrid power plants' operational behavior depends on underlying design choices, understanding what configurations of hybrids are likely to be deployed in the near-future is important for bulk power system planners responsible for ensuring overall system reliability and planning the transmission network. We use historical wholesale market power prices in the seven U.S. organized wholesale power markets from 2012–2019 to calculate hybrid net values, subtracting costs from revenues, across a wide range of wind and solar hybrid configuration choices to evaluate trends in the commercial development of hybrids and identify factors that may alter those trends. Configuration choices considered here include battery duration, battery power capacity, size of the grid interconnection capacity relative to the generator power capacity, the size of PV panels relative to the inverter capacity, and the way that batteries and generators are coupled. We find that the battery duration and battery capacity have the largest impact on the net value of solar and wind hybrids, with the most attractive hybrids having a two-hour battery duration. We find that it is more attractive to set the interconnection capacity to accommodate simultaneous discharge of the generator and the battery, as opposed to limiting the interconnection capacity to the generator power rating, particularly for solar hybrids in the ERCOT and SPP markets. The choice between AC and DC coupling and the sizing of the PV panels relative to the inverter in solar hybrids are secondary to other configuration decisions. Our analytical results align with current commercial trends of online and proposed hybrid projects, thereby suggesting that the net value framework we employ can be used to understand recent commercial hybrid development activity.



1. Introduction and Motivation

Deployment and commercial interest in renewable hybrid power plants connected to the bulk power system are rapidly growing in the United States [1] and globally [2]. While definitions of hybrids differ [3], here we focus on variable renewable generators and battery energy storage systems that share a common point of interconnection with the bulk power system. Potential motivations for co-locating variable renewable generators and storage include supportive policies and procurement programs [4], attractive economics associated with cost synergies and provision of grid services [5], technical challenges with integrating growing amounts of variable and uncertain generation into the power system [6], and demand from customers that prefer controllable or dispatchable assets [7].

Hybrid power plants can behave differently than standalone variable renewables and standalone storage, and the behavior of hybrids depends on the overall configuration. The nature of hybrids joining multiple components together, however, means there are myriad potential configuration options. Configuration choices considered here include battery duration, battery power capacity, size of the grid interconnection capacity relative to the generator power capacity, the size of PV panels relative to the inverter capacity, and the way that batteries and generators are coupled. Understanding what configurations of hybrids are likely to be deployed in the near future is important for bulk power system planners responsible for ensuring overall system reliability and planning the transmission network. Guidelines for conducting reliability studies with hybrids, for example, highlight the importance of assumptions regarding how and when hybrids will operate, which depends in part on the configuration [8]. Hybrid configurations are also important to understand for market designers responsible for providing opportunities for resources to efficiently participate in wholesale power markets [9], other market participants whose investment decisions depend on expectations of demand and supply of wholesale market services, and policy makers interested in supporting power systems that balance reliability, affordability, and sustainability.

However, the logic behind hybrid project developers' choices of what particular configuration to deploy is not always well understood. Furthermore, potentially important factors in decisions are uncertain and changing. These important factors include costs of components, availability of incentives, and demand for wholesale market services. Hence, predicting what configurations are likely to be deployed in the near future requires improving our understanding of hybrid developer decisions and how sensitive decisions are to changes in underlying factors.

There is not a consensus on the criteria and methodology for designing hybrids. One common approach is for researchers to define certain technical specifications and then identify the configuration that can meet those specifications at least cost. Technical specifications in this case can include specific aggregate generation profiles [10,11], performance parameters [12], and reliability or availability thresholds [13]. Numerous tools and studies [14] are available based on this technical specifications perspective.

An alternative approach, particularly relevant to planning bulk power systems, is to use a capacity expansion model to identify hybrid configurations. These models evaluate candidate resource options, each defined by performance capabilities and costs, and system-wide reliability constraints to find the portfolio that meets a planning objective such as maximization of welfare or minimization of total system costs. While significant progress has been made in representing variable renewables [15] and storage in capacity expansion models [16], there are few examples of

capacity expansion models that evaluate a wide range of hybrid configuration options [17]. One exception is that Eurek et al. [18] demonstrate the ability to include a DC-coupled PV and battery hybrid as a candidate resource in a capacity expansion model, though they call for additional research to incorporate region-specific configurations and endogenous system sizing into the model.

Instead of fully evaluating a portfolio of candidate resources, similar economic principles can be used to find attractive candidates based on a marginal analysis of system value, often represented by wholesale market revenue and costs [19,20]. The approach outlined by Joskow [21] is to compare expected revenue to costs and only build those whose value exceed costs. Mowers and Mai [22] similarly argue that attractive technologies are those with the highest profitability, which could be measured as the ratio of revenue to costs. Comparisons of revenue and costs have been used to evaluate variable renewables [23], storage [24], and, based on recent trends, renewable hybrids. Jafari et al. [25], for example, use wholesale market prices and component costs in the New York region to evaluate the revenues and costs of different offshore wind hybrids configurations while accounting for battery degradation. They find that revenue can be overestimated by 35% if battery degradation is not accounted for in operational decisions. Schleifer et al. [26] compare the benefits, estimated from simulated future marginal energy and capacity costs, and projected component costs of different PV and storage hybrid configurations in three U.S. regions. They find that the most attractive configuration varies by region because of differences in grid conditions.

The configuration options and regions examined in these papers are limited. Options in Schleifer et al. [26] are limited to the choice of coupling and decisions about grid charging; they did not assess the impact of battery size or inverter loading ratio. They accounted for storage degradation by limiting the batteries to one cycle per day and included a battery replacement cost after 10 and 20 years. From a practical perspective, this means that no single resource is available to address questions about relative economic attractiveness of hybrid configurations pertinent to decision makers across the U.S. wholesale market regions. More generally, there is an open question of whether an economic assessment of hybrid configurations based on comparisons of revenues and costs can explain trends in hybrid configurations being commercially deployed.

While we acknowledge the current commercial interest in hybrids, in this paper, we do not explore *why* developers are choosing to co-locate storage and variable renewable energy (VRE) generation or *whether* hybrids are economically viable in the first place. Instead, we seek to understand the *trends* in the commercial development of hybrids and to *identify factors* that may alter those trends through an evaluation of the costs and revenues of different hybrid configurations, enabling planners to make more informed assumptions about the configuration and behavior of hybrids. We also seek to understand which configuration choices are more impactful than others on market value and costs. For configuration options that have a small impact on value and costs, developers could be somewhat indifferent to their choice, making it difficult to have confidence in discerning which configuration choice developers would select.

In this paper, we analyze the variation in hybrid net value, a metric defined in the Methods, across a wide range of wind and solar hybrid configuration choices in the seven U.S. organized wholesale power markets using historical wholesale market power prices from 2012–2019 and recent hybrid component costs. We calculate the net value in a way that accounts for how the usage of storage affects the useful life of battery components and therefore their annualized costs. With these results, we identify hybrid configuration choices that have the greatest impact on net value and identify how attractive configurations change under different plausible scenarios. We compare the

attractive hybrid configurations to recently developed hybrids or projects in the near-term development pipeline to qualitatively evaluate the explanatory power of the approach. In conducting this case study, we demonstrate an analytical approach that other planners could use with more location specific or case specific parameters to evaluate hybrid development trends.

We note that the use of historical observed wholesale market prices can be complementary to other approaches that use modeled future wholesale prices for an evolving grid. Our analysis based on wholesale prices provides only a sense of the potential economic value on the margin, whereas wholesale power market simulations or capacity expansion models can consider changes in configurations as the deployment of hybrids increases or other structural shifts impact the value of various technologies.

Section 2 describes the three key elements that are used to evaluate hybrid configurations: the hybrid market value, the battery lifetime accounting for its usage, and the hybrid costs. Section 3 details the case study with an overview of the hybrid configuration options, the scenario definitions, and the data and assumptions. Section 4 shows how the net value of hybrids varies over all combinations of configurations, scenarios, regions, and years, then explores which configuration options produce the highest net value. To assess the explanatory power of the approach, Section 5 qualitatively compares the analytical results to recent trends in commercial deployment of hybrids and addresses important caveats. Finally, Section 6 summarizes the findings and provides recommendations for future work.

2. Methods

We compare hybrid configurations by calculating the net value of each configuration. Net value is defined as the difference between the annual market revenue of power bought and sold at wholesale market prices — referred to as the market value — and the annualized cost of the hybrid equipment, all normalized by the annual VRE generation. The cost of the hybrid depends in part on how battery cycling impacts its useful lifetime. This section describes how we simulate the hybrid dispatch, calculate hybrid market value based on the dispatch, determine the lifetime of the battery depending on how it is cycled, estimate the cost of different hybrid configurations, and finally compute the "hybrid net value" metric normalized over annual VRE generation, Figure 1.

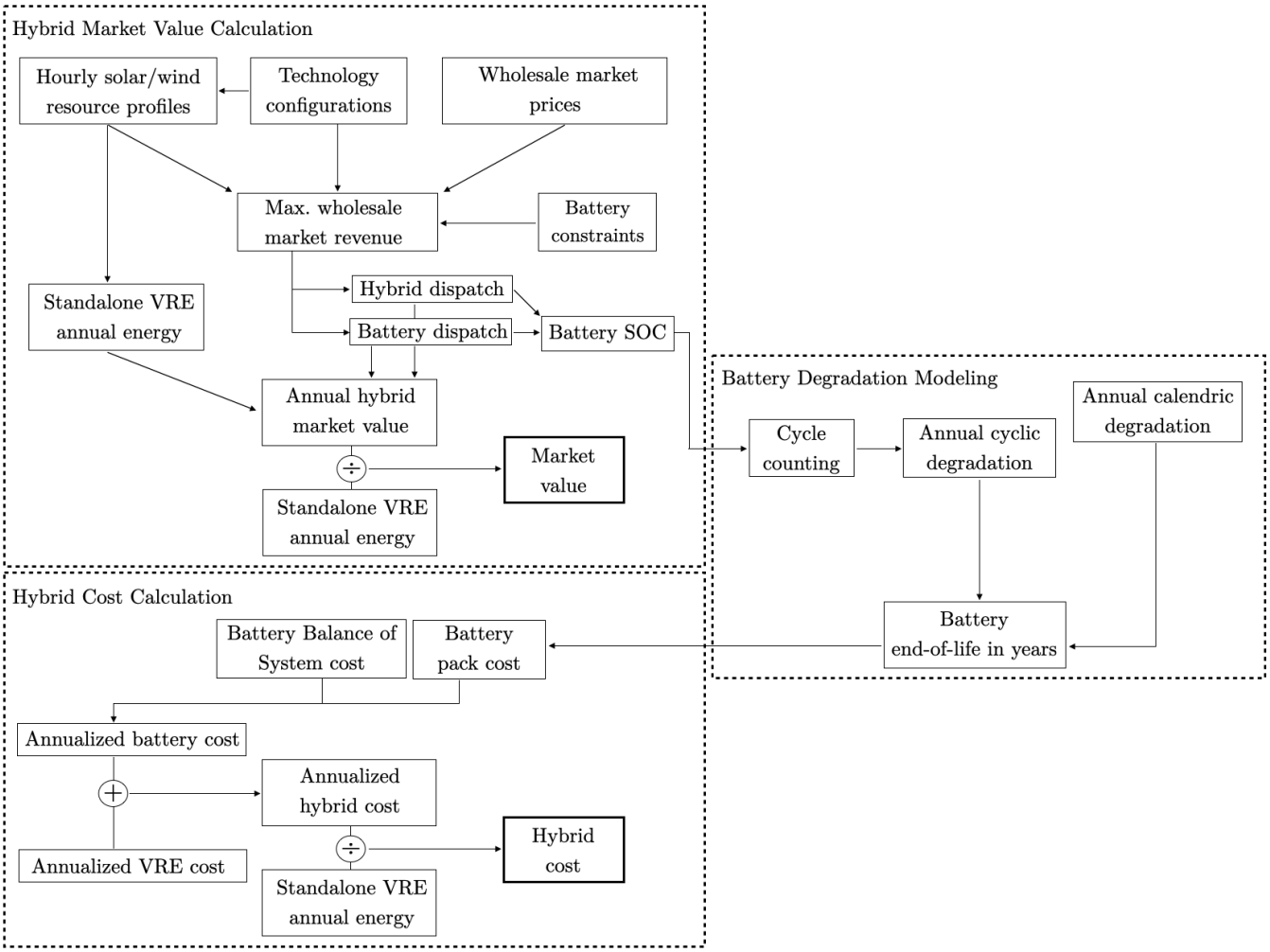


Figure 1. Illustration of the hybrid dispatch and annual market value calculation (top left), battery lifetime assessment (right) and annualized cost calculation (bottom left).

2.1 Hybrid Dispatch

We use a linear optimization program to find the hybrid dispatch that maximizes revenue based on historical wholesale power market prices. Here we provide only a high-level summary as details of the optimization program are the same as used in Gorman et al. [27]. The objective of the optimization is to maximize revenue from buying and selling power from the hybrid at an hourly varying wholesale power price, accounting for a linear degradation penalty applied to the battery charge and discharge power. The linear degradation penalty can also be thought of as a hurdle rate that prevents the battery from being cycled for low value opportunities, which impacts the dispatch decisions but is not otherwise treated as an actual expenditure. The hourly wholesale power price is the energy price plus an hourly capacity price adder, described in Section 2.2, such that the revenue and dispatch incorporate both the energy and capacity value of the hybrid. The hybrid dispatch is constrained by the energy capacity of the battery, the power rating of the battery, the power from the renewable generator using historical hourly weather data, and the point of interconnection capacity. Charge and discharge of the battery impacts the state of charge, accounting for losses. We adjust constraint parameters depending on whether the battery is allowed to charge from the grid. Similarly, to evaluate scenarios where hybrids provide ancillary

services (AS), in addition to energy and capacity, we include the additional regulating reserve revenue in the objective function and activate constraints that account for the tradeoff between providing energy versus providing regulating reserves. Finally, we include additional constraints and adjust parameters to model solar hybrids with either an AC-coupling, where both the battery and generator have individual inverters, or a DC-coupling where the battery and PV are connected on the DC side of a shared inverter.

As in Gorman et al. [27] we use the optimization program to generate either an optimistic or pessimistic dispatch of the hybrid. The optimistic dispatch comes from assuming the hybrid has perfect foresight of hourly real-time wholesale power prices and renewable generation. The pessimistic dispatch is based on the hourly day-ahead prices and the previous day's renewable generation. In this case, the realized charge and discharge dispatch schedule is adjusted by constraining the optimized schedule with the operating day's actual renewable generation profile as well as limits on the battery in a post-process calculation.

2.2 Hybrid Market Value Calculation

We calculate the annual hybrid market value as the product of the hourly wholesale power prices and the net power from both the generator and battery delivered (or in the case of battery charging, consumed) across the point of interconnection (POI), summed across the year. The hourly wholesale prices are the real-time energy market prices plus an hourly capacity price adder, leading to a hybrid market value that represents both energy and capacity value. As in Gorman et al. [27] the capacity price adder is based on allocating a region- and year-specific capacity price to the top 100 net load hours. Hybrids that deliver power during these top 100 net load hours earn additional revenue beyond the energy market revenue, representing an approximation of the capacity value. Previous analysis indicates that this approximation is reasonable when benchmarked against a probabilistic representation of power system reliability [28,29]. In scenarios where hybrids provide ancillary services, the revenue is further increased based on the product of the hourly regulating reserve price and the provision of regulating reserves from the co-optimized hybrid dispatch. As discussed in greater detail elsewhere, our use of historical regulating reserve prices indicates the marginal value, which is expected to decrease with growth in storage assets providing reserves [30]. By focusing only on wholesale market, we ignore other potentially available revenue streams (e.g., renewable energy credits) or societal benefits that may impact the absolute level of individual configurations, but should be less impactful on the relative difference between configurations.

2.3 Battery Degradation Modeling

While we use a simple linear degradation penalty parameter to determine hybrid dispatch, as described in Section 2.1, we calculate the cost of the battery based on a lifetime estimate from a detailed non-linear degradation model. Following the approach by Yan et al. [31], we define the lifetime of the battery pack component as the time it takes to reach 60% of initial capacity (or 40% capacity fade). We assume that two primary sources of capacity fade, calendric degradation and cyclic degradation, simply add together based on the superposition principle to result in the annual capacity fade in Eq. 1.

$$T = 1/(L_{cal}^{annual} + L_{cyc}^{annual}) \quad \text{(Eq. 1)}$$

Where,
T = battery pack lifetime (yr)

L_{cal}^{annual} = Annual calendric capacity fade relative to end-of-life criterion (% capacity /yr)
L_{cyc}^{annual} = Annual cyclic capacity fade relative to end-of-life criterion (% capacity /yr)

As in Yan et al. [31], we assume that absolute annual calendric degradation is 2%, such that the pack would reach the end-of-life criterion (40% capacity fade) after 20 years without any cycling. The end-of-life is less than 20 years, however, because of cyclic degradation that depends on how the battery is dispatched. Following the approach by Yan et al. [31], we estimate cyclic degradation using the timeseries of the state of charge from the hybrid dispatch and manufacturer-provided capacity fade relationships for a Lithium Iron Phosphate (LFP), or LiFePO4/C, battery.

First, we extract the number and depth of battery cycles from the dispatch timeseries through a rainflow counting algorithm (RCA), using the Python package *rainflow 3.0.1*, an implementation of the ASTM E1049-85 algorithm for fatigue analysis. The RCA identifies and counts the depth of all cycles contained in the state of charge timeseries including irregular, overlapping, and half-cycles for each depth range, following a well-established technique to estimate metal fatigue [32].

Next, we map cycles to percentage capacity fade. The non-linear relationship between depth of discharge of *full* cycles (DOD_i) and battery pack capacity retention (shown as the number of full cycles *N* until 60% of initial capacity is left) is described by a fit to empirical degradation data in Eq. 2 [31], representing the marginal capacity fade due to a charge-discharge cycle from a given battery state-of-charge (SOC_i, *i* between 0 and 100%) and full discharge (SOC_0). We consider all cycles as *partial* cycles with a depth of discharge DOD_{ij} equal to the charge-discharge cycle from a state of charge SOC_i to SOC_j (*i, j* between 0 and 100%), producing a level of degradation equal to half of the difference between the degradation of two full cycles of depth of discharge DOD_i and DOD_j. This relationship is shown in Eq. 3 [31]. Finally, we calculate the capacity fade over one year due to cycling by adding all of the equivalent full cycles, Eq. 4. This linear damage hypothesis has its shortcomings, namely that it does not take into account the probabilistic nature of fatigue or the effect of the specific sequence in which high and low depth cycles occur on the degradation process, though it is adequate for our purposes.

$$N_{DODi} = 28270e^{-2.401DODi} + 2.214e^{5.901DODi} \quad \text{(Eq. 2)}$$

$$L_{DODij} = \frac{1}{2}\left|\frac{1}{N_{DODi}} - \frac{1}{N_{DODj}}\right| \quad \text{(Eq. 3)}$$

$$L_{cyc}^{annual} = \sum_{k=1}^{K} L_{DODij} \quad \text{(Eq. 4)}$$

L_{DODij} = Capacity fade due to battery charge or discharge from SOC_i to SOC_j (% capacity)
L_{cyc}^{annual} = Annual cyclic capacity fade relative to end-of-life criterion (% capacity /yr)

2.4 Hybrid Cost Calculation

The annual hybrid cost is the annualized capital cost plus the fixed O&M cost of the hybrid. The capital costs are based on scaling the sum of the annualized capital cost of the VRE generator and the annualized cost of the battery by a hybridization cost reduction factor, *R*, which represents non-hardware and balance of system (BOS) cost synergies arising mostly from shared site preparation, land acquisition, permitting, installation labor, overhead, profit, and electrical equipment [33] of the co-located generator and battery, Eq. 5. Although the hybridization cost

reduction factor could vary across configurations depending on the relative contribution of non-hardware and BOS costs on total hybrid costs and whether the hybrid is AC or DC coupled, we assume R is constant across all configurations, as described further in Section 3.3.

$$Annual\ hybrid\ cost = (1 - R)(C_{VRE} + C_B) + (OM_{VRE} + OM_B) \quad \text{(Eq. 5)}$$

Where,
R = Reduction in hybrid capital costs compared to costs of underlying components
C = annualized capital costs of wind/solar (VRE) or battery (B) systems ($/yr)
OM = operating costs of wind/solar (VRE) or battery (B) systems ($/yr)

We include in the annualized capital cost of the VRE generator an estimate of the interconnection cost. We only include an interconnection cost in the annualized capital cost of the battery for configurations in which the point of interconnection capacity is increased beyond the level of the VRE generator nameplate capacity.

For solar generators the capital cost depends on the inverter loading ratio (ILR). Increasing the inverter loading ratio increases the cost of PV panels without impacting the cost of the inverter and interconnection capacity. A somewhat analogous design choice for wind turbines is the ratio of the swept area of the blades to the generator nameplate capacity [34]. However, we assume a consistent wind turbine design, and hence generator capital cost, for all wind hybrids.

The annualized battery capital cost is composed of the cost of the battery pack, whose lifetime used in the annualization calculation depends on the way the battery is cycled, and the cost of the BOS, whose lifetime is independent of the operation of the battery pack. The pack and BOS costs each have a portion of the cost that scales with the power capacity and a portion that scales with the amount of energy that can be stored in the battery. From these relationships, the battery costs vary with the duration and size of the battery system, depending on the configuration.

Additional details and formulas used in the calculation of component capital costs and for annualizing costs are in Supplementary Note 1.

2.5 Hybrid net value metric

The primary metric of interest in this analysis is hybrid net value, which is the difference between the annual hybrid market value and the annual hybrid cost, Eq. 6. To get the hybrid net value in $/MWh terms, both of these annual terms are divided by the annual energy produced by the standalone VRE generator, pre-curtailment. For solar hybrids, this means that the denominator increases in configurations with higher ILR. In contrast, the denominator is not impacted by the addition of batteries or the ability of DC-coupled batteries to capture otherwise clipped energy; these changes only impact the annual hybrid market value or hybrid cost in the numerator.

$$Hybrid\ net\ value = \frac{Annual\ hybrid\ market\ value}{E_{VRE}} - \frac{Annual\ hybrid\ cost}{E_{VRE}} \quad \text{(Eq. 6)}$$

Where:
E_{VRE} = annual energy generation by the standalone VRE generator (MWh/yr)

We choose this metric because it allows us to directly compare the economic attractiveness of different configurations. A configuration with a higher net value is relatively more attractive than a

configuration with a lower net value.

3. Case Study: Wind and Solar Hybrids in Seven U.S. Markets

We use historical wholesale market prices and weather patterns to evaluate hybrid net value across configurations in each of the seven organized wholesale power markets in the United States. Here we describe the configuration choices, different scenarios, and sources for data and assumptions key to the analysis. Configuration choices are largely endogenous to the hybrid developer, while scenarios reflect exogenous factors related to technical, regulatory, or market conditions. Using these data and assumptions, we calculate the net value of each hybrid configuration in each region.

The calculations use the open-source optimization solver COIN-OR Linear Programming Interface, implemented using the JuMP package in Julia on the Lawrencium high performance computer.

3.1 Configuration Choices

Hybrids have either a 100 MW_{AC} wind or solar generator. This VRE generator is coupled with batteries of capacities ranging between 25 MW to 100 MW. The amount of energy storage is scaled relative to the discharge capacity such that the energy to power ratio, or the battery duration, is between 2 and 8 hours. For solar hybrids, the DC rating of the single-axis tracking PV panels can range from 130 MW_{DC} to 210 MW_{DC}, leading to inverter loading ratios of 1.3 to 2.1. Also for solar hybrids, the batteries can be DC-coupled where it is connected to a DC bus shared with the PV panels on the DC side of the inverter. With DC-coupling, power from the PV panels can be sent directly into the battery or instead sent to the grid via the shared inverter. Alternatively, the batteries can be AC-coupled where the batteries and generator each have their own inverter and connect to the grid on the AC side through a common point of interconnection. The capacity of the common point of interconnection can be either 100 MW_{AC}—the AC capacity of the VRE generator—or in the case of AC coupled hybrids, the capacity can be increased by the battery capacity. The set of configuration options evaluated in this study are summarized in Table 1. As a point of comparison, we also present a limited set of results based on the net value of a standalone VRE generator. Where included, we represent the standalone VRE generator as a hybrid with 0 MW battery capacity and 0-hour battery duration. The standalone solar generator has an ILR of 1.3. For the standalone generators, the point of interconnection capacity is equivalent to its nameplate capacity.

Table 1. Hybrid configuration choices.

Configuration Choice	Values
Battery Duration	2, 4, 6, 8 hours
Battery Capacity	25, 50, 75, 100 MW
Point of Interconnection Capacity (AC-coupled only)	100 MW_{AC} or 100 MW_{AC} + battery capacity
System Coupling (solar hybrids only)	AC-coupled or DC-coupled
Inverter Loading Ratio (solar hybrids only)	1.3, 1.7. 2.1

3.2 Scenarios

Several factors that are somewhat outside of the hybrid developers' control affect the hybrid net value, and more importantly for the purpose of this analysis, could alter the net value of one configuration relative to another. To examine the robustness of the findings, we calculate net value under a wide range of scenarios, described in Table 2. In the Baseline scenario we use a $5/MWh degradation penalty when determining the dispatch of the hybrid [35], optimistically assume perfect foresight of real-time prices and renewable generation, allow the battery to charge from the renewable generator or the grid, exclude the Federal Investment Tax Credit and Production Tax Credit incentives, and assume that the hybrid does not participate in ancillary service markets.

Table 2. Scenario definitions.

Scenario	Abbreviation	Degradation Penalty ($/MWh)	Dispatch	Grid Charging	Incentives	Ancillary Services
Baseline	**BASE**	5	Perfect foresight	Allowed	None	None
Degradation	**DEG 0**	0	Perfect foresight	Allowed	None	None
	DEG 25	25	Perfect foresight	Allowed	None	None
Imperfect Foresight	**FOR**	5	Imperfect foresight using day-ahead prices and previous day renewables	Allowed	None	None
No Grid Charging	**NO GC**	5	Perfect foresight	Restricted to charge from renewables	None	None
Incentives	**INCT**	5	Perfect foresight	Solar or wind with ITC is restricted to charge from renewables, wind with PTC is allowed to charge from grid	Solar and battery get 26% ITC, wind gets higher of $18/MWh PTC or 18% ITC for wind and battery	None
Ancillary Services	**AS**	5	Perfect foresight	Allowed	None	Battery can provide regulating reserves

3.3 Data and Assumptions

We sited one wind and one solar hybrid at a representative location in each of the seven organized wholesale market regions of the U.S. We model the hybrid at the location of an existing wind or solar plant nearest to the capacity-weighted centroid of all currently-installed wind or solar plants.

We limit the candidate sites to those with an annual capacity factor within 10% of the average capacity factor of all existing wind or solar plants in the market, Table 3. The location of the final plants selected in relationship to the regional capacity-weighted centroid of the currently deployed wind or solar plants can be seen in Figure 2. We then modeled generation using historical wind speed or solar insolation data for historical years between 2012-2019 following the approach used in Gorman et al. [27]. We use wholesale market prices from a trading hub near the plant location, accessed from ABB Velocity Suite. In the Ancillary Services scenario we use regulation reserve prices from the AS Zone associated with the trading hub. Capacity prices and hourly net load for each region are the same as used in Gorman et al. [27].

As described in further detail in Supplementary Note 1, capital cost, O&M cost, and financing assumptions for VRE generator and battery components are derived from the literature, largely building on data and assumptions from the National Renewable Energy Laboratory's Annual Technology Baseline [36] and the Pacific Northwest National Laboratory's Energy Storage Cost and Performance Database [37]. We assume that interconnection costs are $\$70/kW_{AC}$ for all sites based on U.S. average interconnection costs for wind and solar plants installed in the U.S. [38]. This is a simplification as actual interconnection costs can vary substantially from site to site. We also assume that co-locating VRE and batteries reduces the capital cost by 6%, parameter R in Eq. 5, based on the reduction in cost of AC-coupled hybrids reported by Feldman et al. after adjusting for differences in the interconnection cost [33]. This cost reduction estimate comes from reductions in non-hardware costs and balance of system costs specific to a PV-battery with a 1.3 ILR, 4-hour duration battery, with a 0.6 battery to PV capacity ratio. We apply this same cost reduction in percent terms to all solar and wind hybrids, which may overstate the cost reduction potential for configurations with high ILR or longer duration batteries. We keep technology costs constant rather than varying costs with historical years. This approach allows for exploration of how wholesale market trends, rather than cost declines, impact hybrid net value. Individual component cost trends are well documented elsewhere [34,39,40].

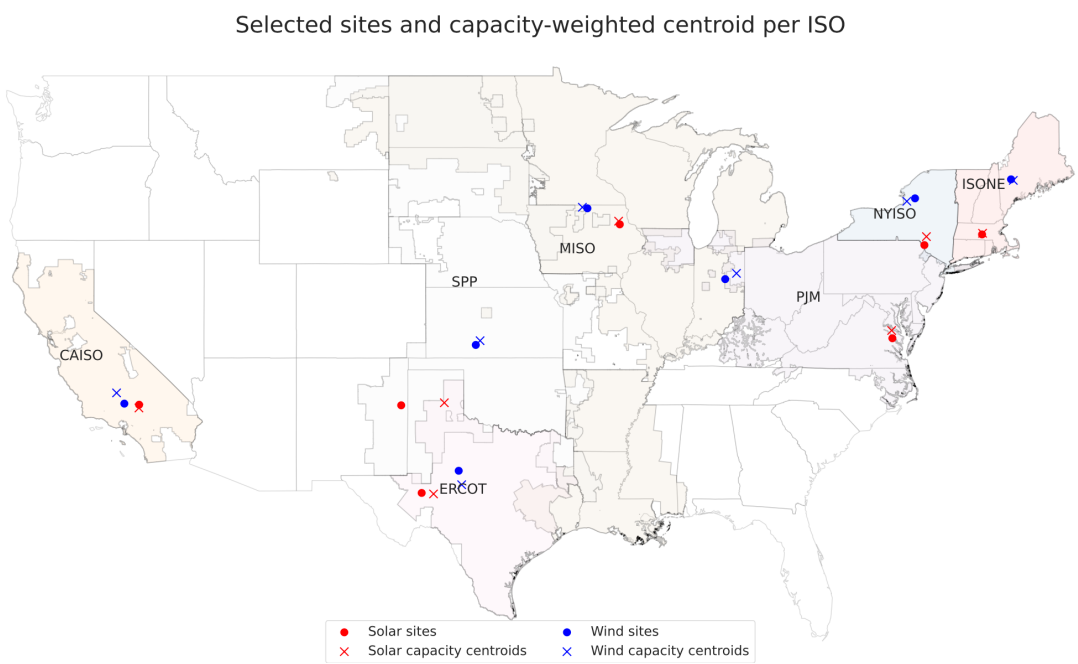


Figure 2. Location of selected representative solar and wind sites and regional capacity-weighted centroids of currently deployed plants.

Table 3. Selected wind and solar sites for hybrid analysis.

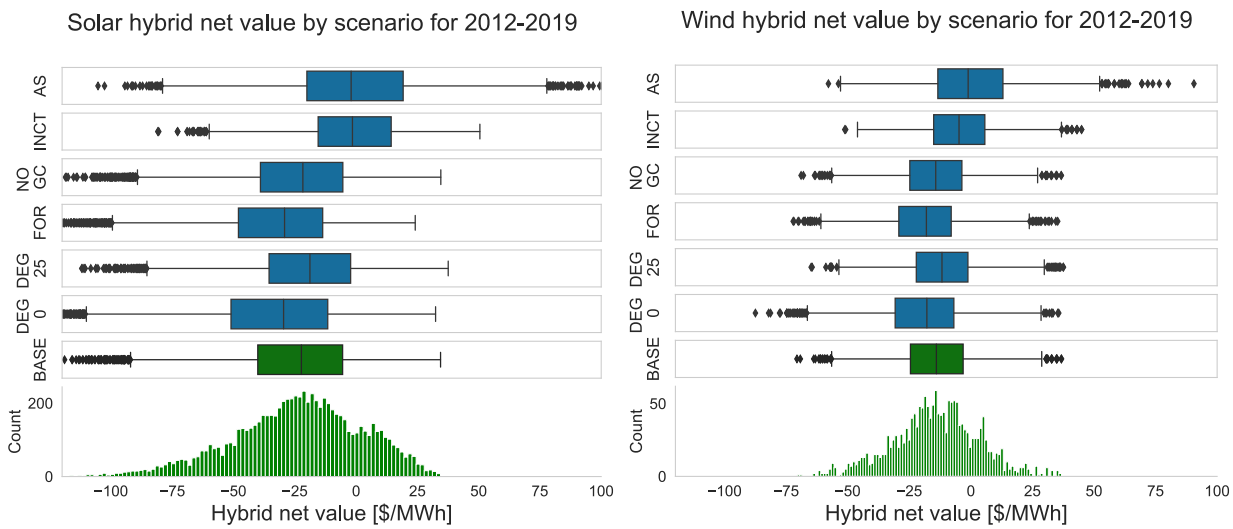
Region	Tech.	Plant Name	Capacity Factor	Percent Deviation from Regional Avg. Capacity Factor	Trading Hub	AS Zone
CAISO	Solar	SEGS III	34.4%	6.0%	TH_SP15_GEN-APND	AS_SP15_P
	Wind	Windstar 1	40.5%	5.0%	TH_SP15_GEN-APND	AS_SP15_P
ERCOT	Solar	Castle Gap Solar Hybrid	31.4%	3.8%	HB_WEST	ERCOT
	Wind	Turkey Track Wind Energy LLC	43.2%	-1.3%	HB_WEST	ERCOT
SPP	Solar	Antanavica Solar	31.5%	7.6%	.Z.WCMASS	REST OF SYSTEM
	Wind	Greensburg	39.2%	3.4%	SECI_SECI	SPP ZONE 1
MISO	Solar	Strawberry Point DPC Solar	23.0%	-1.4%	ALTW.AZ	MISO
	Wind	Northern Iowa Windpower II	37.5%	-7.4%	SMP.AZ	MIDCONTINENT ZONE 5
PJM	Solar	Essex Solar Center	21.8%	0.2%	DOMINION HUB	PJM-RTO ZONE
	Wind	Wildcat Wind Farm I, LLC	33.3%	5.1%	AEP-DAYTON HUB	PJM-RTO ZONE
NYISO	Solar	Baer Road CSG	24.5%	0.6%	HUD VL (ZONE G)	HUD VL (ZONE G)
	Wind	Maple Ridge Wind Farm	32.8%	-8.1%	MHK VL (ZONE E)	MHK VL (ZONE E)
ISO-NE	Solar	Caprock Solar 1 LLC	23.2%	1.1%	SPS_SPS	SPP ZONE 3
	Wind	Saddleback Ridge Wind Farm	49.4%	3.3%	.Z.NEWHAMPSHIRE	REST OF SYSTEM

4. Results

The net value of various hybrid configurations across market regions and scenarios are estimated using the model and data described in the previous section. After enumerating the net value for each configuration-market-year combination, we identify which hybrid configurations yield the highest net value within specific scenarios. While we rely on limited comparisons of hybrid configurations to standalone VRE generators, our focus is not on making the economic case of hybrids against standalone VRE or standalone storage. Instead, these results primarily provide insights into the trends and relative economic attractiveness among hybrid configurations.

4.1 Hybrid Net Value Across Scenarios

For each scenario described in Table 2, we evaluate the net value of each solar and wind hybrid configuration in the seven regions using generation and wholesale market prices for each year between 2012-2019, Figure 3. The resulting net values in the Baseline scenario are shown as a histogram and a box plot in green, while only the boxplot is shown for the other scenarios. With the Baseline assumptions, the median of the net value across all configurations, regions, and years is -$22/MWh for solar and -$14/MWh for wind hybrids. Even so, 20% of the cases (i.e., a configuration-region-year combination) have a positive net value in the Baseline scenario, indicating that even in the Baseline scenario, which has no incentives, some hybrid configurations can be attractive investments.



(a) **(b)**

Figure 3. Range of hybrid net value by scenario for all configurations with (a) solar and (b) wind. Note: Each data point represents a configuration-region-year combination. DEG 0 & DEG 25: Degradation scenarios with $0 and $25 linear throughput penalties; FOR: Imperfect Foresight scenario for hybrid dispatch; NO GC: No Grid Charging scenario; INCT: Incentive scenario which includes ITC/PTC incentives; AS: Ancillary Services scenario allows batteries to provide regulating reserves.

The scenarios that most impact hybrid net value are the Incentives and Ancillary Services scenarios. Incentives provided by the ITC and PTC increase the hybrid net value by $21/MWh for solar (even accounting for the restriction on grid charging) and $9/MWh for wind, on average.[1] These incentives are available to plants that recently became operational, though they are slated to step down to lower levels in future years [41]. Allowing the battery to provide regulating reserves in the Ancillary Services scenario increases the net value relative to the Baseline scenario by $20/MWh for solar and $13/MWh for wind, on average. Although provision of ancillary services is attractive based on recent wholesale market prices, these markets are shallow and regulation prices are expected to decline as more storage comes online [30]. The scenarios that change assumptions about the degradation penalty, foresight in scheduling dispatch, and grid charging all impact the net value of solar and wind hybrids by roughly ± $7/MWh.

The use of a higher degradation penalty ($25/MWh) marginally *increases* the hybrid net value

[1] The values reported as "averages" correspond to the median of the distribution of hybrid net value, for the specified scenario.

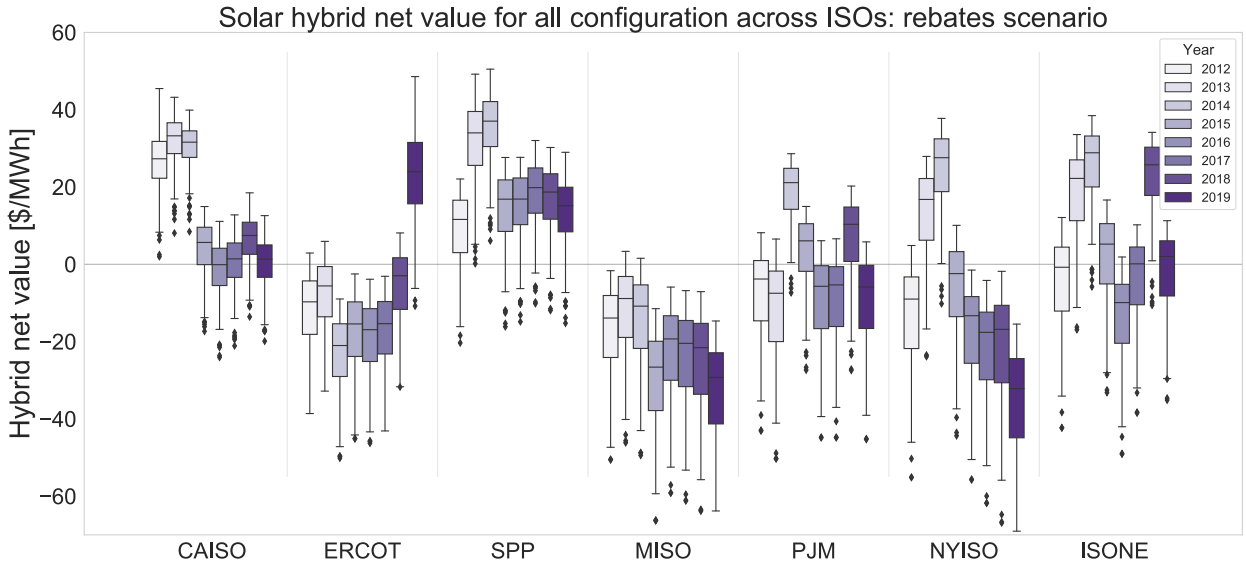
relative to the Baseline scenario by $3/MWh for solar and $2/MWh for wind. The higher penalty results in the battery forgoing opportunities to arbitrage between small price differences, and therefore fewer cycles. Fewer cycles lead to a longer battery life, and because of the relatively high cost of storage, a cost reduction that is greater than the forgone arbitrage revenue. This result, though overall small in magnitude, highlights the importance of capturing the trade-off between increased revenues and increased battery costs associated with battery cycling, further illustrated in Supplementary Note 2. Unfortunately, the trade-off is non-linear and battery costs are uncertain, making it non-trivial to find the degradation penalty that maximizes net value. At best, we are confident that the degradation penalty should be above zero and that our net value results are not particularly sensitive to degradation penalty assumptions between $5–25/MWh, even though the dispatch decisions are sensitive to this assumption.

Similar consideration of the revenue and battery cost tradeoff explains why restricting batteries to charge from renewables in the No Grid Charging scenario slightly increases solar hybrid net value relative to the Baseline scenario (though it slightly decreases it for wind hybrids), by ± $0.5/MWh. For solar and wind hybrids, restricting grid charging results in less revenues than the Baseline scenario because the battery is no longer able to charge during periods of low prices. Nevertheless, we find that for solar the revenue reduction from restricting grid charging is smaller than the reduction in battery cost associated with fewer cycles and a longer life.

Given that recently and soon-to-be constructed commercial hybrids are eligible for the ITC and PTC incentives, and the Incentives scenario leads to the highest net value for hybrids, all of the remaining results will focus on the Incentives scenario.

Examining how the hybrid net value varies by region and by year in the Incentives scenario, **Figure 4**, highlights the importance of underlying wholesale market trends in driving the net value of hybrids. This can be observed in the way variations between years are similar for solar hybrids (top) and wind hybrids (bottom), albeit solar configurations produce a wider range of net values than wind configurations. Importantly, the differences across years in each market are only due to changes in wholesale prices and renewable generation profiles, not due to variations in hybrid technology costs since technology costs are kept constant in this analysis. An example of the similar impact of wholesale market trends on solar and wind hybrid net value is in 2014 in the three eastern markets of PJM, NYISO, and ISO-NE. The net value of wind and solar hybrids in these markets is higher than other years due to high wholesale market prices associated with a cold winter weather event and constrained natural gas infrastructure [42].

Market trends do not always similarly impact solar and wind hybrids, however. Rapid growth in solar in CAISO between 2012-2019 shifted the timing of high and low wholesale market prices [6], leading to a significant decline in standalone solar, which ultimately impacts the net value of solar hybrids despite their dispatchability, while the value of wind hybrids in the same market has remained steady. As shown in prior work, the decline in CAISO solar hybrid value corresponds with significant value decline of standalone solar in the region while the value of storage increased, though to a lesser amount, between 2012 and 2019 [27]. Figure 5 shows how some solar hybrid configurations have higher net value than the corresponding standalone solar configuration. On the other hand, high wholesale market prices in the summer afternoons in ERCOT in 2019 associated with low planning reserve margins [43] disproportionally increased the net value of solar hybrids relative to the increase in net value of wind hybrids.



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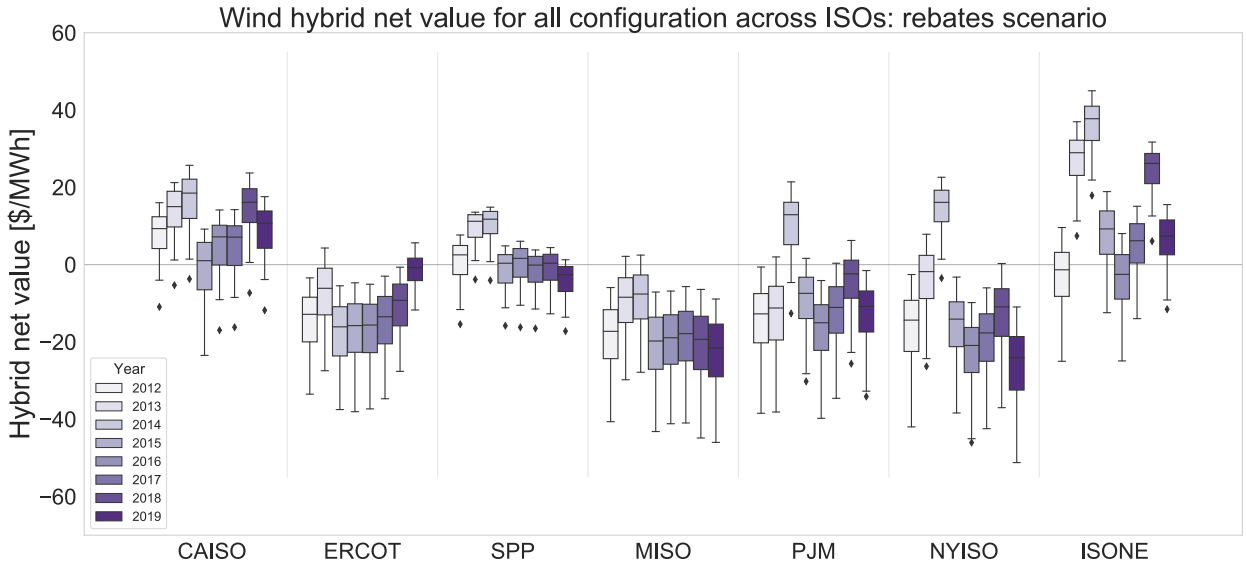


(b)

Figure 4. Variation in hybrid net value across regions and years in the Incentives scenario for all (a) solar and (b) wind configurations. Note: Yearly variation results from the underlying solar, wind, and market price data, not from historical changes in hybrid costs. Instead cost data is constant and comes from 2020 estimates, as described in the Methods. These results allow for exploration of how wholesale market trends, rather than cost declines, impact hybrid net value.

4.2 Hybrid Net Value Across Configurations

In this section, we examine the net value based on the configuration choices: battery duration, battery capacity, point of interconnection capacity, AC vs. DC coupling, and inverter loading ratio (ILR). We use the average net value across recent years (2017-2019) for the remaining analysis of hybrid configurations. The market conditions in these recent years are likely more representative of the conditions developers expect in the future than the earlier years. We similarly continue to focus on the Incentives scenario, though we highlight examples where findings differ depending on

the scenario.

We start by comparing the net value of hybrids to net value of a standalone wind and solar generator, which is represented in Figure 5 as a configuration with 0 MW battery and 0-hour duration. For the majority of regions, the net value of at least one hybrid configuration exceeds the net value of the standalone generator, with the exception of standalone solar exceeding the net value of all solar hybrid configurations in MISO and standalone wind exceeding the net value of all wind hybrids in MISO, PJM, and NYISO, Figure 5. Attractive solar hybrids are more common than attractive wind hybrids in the Incentive scenario because the tax incentive used by solar, the ITC, reduces the capital cost of the battery whereas the tax incentive used by wind, the PTC, does not.[2] As a result, in the Baseline scenario without incentives, the standalone solar generator is more attractive than all solar hybrids configurations for all regions except CAISO, ERCOT and SPP. In contrast, the relative attractiveness of wind configurations does not change between the Incentives and Baseline scenario. Finally, we note that hybrids are less attractive than standalone generators in the Imperfect Foresight scenario that both has no incentives and uses a naïve, but implementable, dispatch strategy, with the exception that at least one wind hybrid configuration exceeds the net value of the standalone generator in SPP (see Supplementary Note 3).

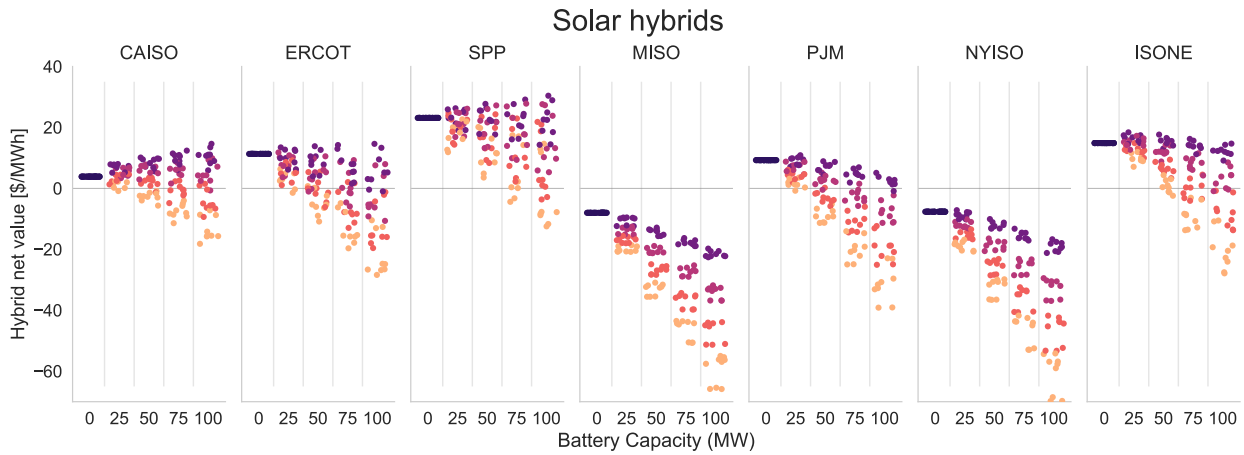
By far, the configuration parameters that most significantly impact hybrid net value are the battery duration and battery capacity, Figure 5. Hybrid configurations with the highest net value have 2-hour duration batteries. While there are instances where the net value of 4-hour and 2-hour duration hybrids are nearly equivalent, the net value of 6-hour and 8-hour configurations is always less than 2-hour batteries. The choice of duration is particularly impactful with large capacity batteries (i.e., 100 MW). At least for current conditions, the costs associated with increasing the duration of batteries outweighs the associated increase in market value. For a specific battery duration and battery capacity, the remaining variation in the net value (shown as differences in the height of dots with similar duration and capacity) is from different choices for the point of interconnection capacity (for AC coupled configurations), AC vs. DC coupling (for solar hybrids), or ILR (for solar hybrids).

Regarding the battery capacity, we find that the most attractive hybrid configurations tend to have battery capacities at one of the extremes. That is, their net value is highest when either battery capacity takes the minimum value (25 MW) or battery capacity takes the maximum value (100 MW). All of the most attractive wind hybrids take the minimum battery capacity, though in CAISO, ERCOT, and SPP the difference in net value between 25 MW or 100 MW battery capacity is negligible (under $3/MWh). Similarly, the 25 MW battery capacity is the most attractive solar hybrid in MISO, PJM, NYISO, and ISO-NE. In contrast, the 100 MW battery capacity hybrid configurations are clearly the most attractive solar hybrids in CAISO, ERCOT, and SPP. In these three regions the more battery capacity that is added to the 2-hour duration solar hybrids, the more the net value increases. Across these three regions, the net value of solar hybrid configurations with 100 MW battery capacity can be $3–11/MWh higher than the net value of standalone solar,[3] though this significant increase in net value largely disappears in the Baseline scenario without incentives or with our pessimistic hybrid dispatch with imperfect foresight (see

[2] Wind generators are in fact eligible for the ITC as an alternative to the PTC, but we find that the PTC is often more attractive even when considering the potential reduction in storage capital cost with the ITC. For larger storage capacities and durations, the ITC can be more attractive for wind hybrids. We update our wind hybrid net value calculations to account for the optimal incentive.

[3] We expect that the solar hybrid configurations with 100 MW storage would continue to be more attractive than standalone PV in the Incentives scenario even if the hybridization cost reduction factor, *R*, were lower than the 6% assumed here. However, some cases where 25 MW hybrids appear more attractive than standalone wind or solar differ when cost reductions from hybridization are modeled differently (See Supplementary Note 4).

Supplementary Note 3). We also caution that significant deployment of hybrids will begin to impact wholesale market prices, eventually limiting these positive net value opportunities.



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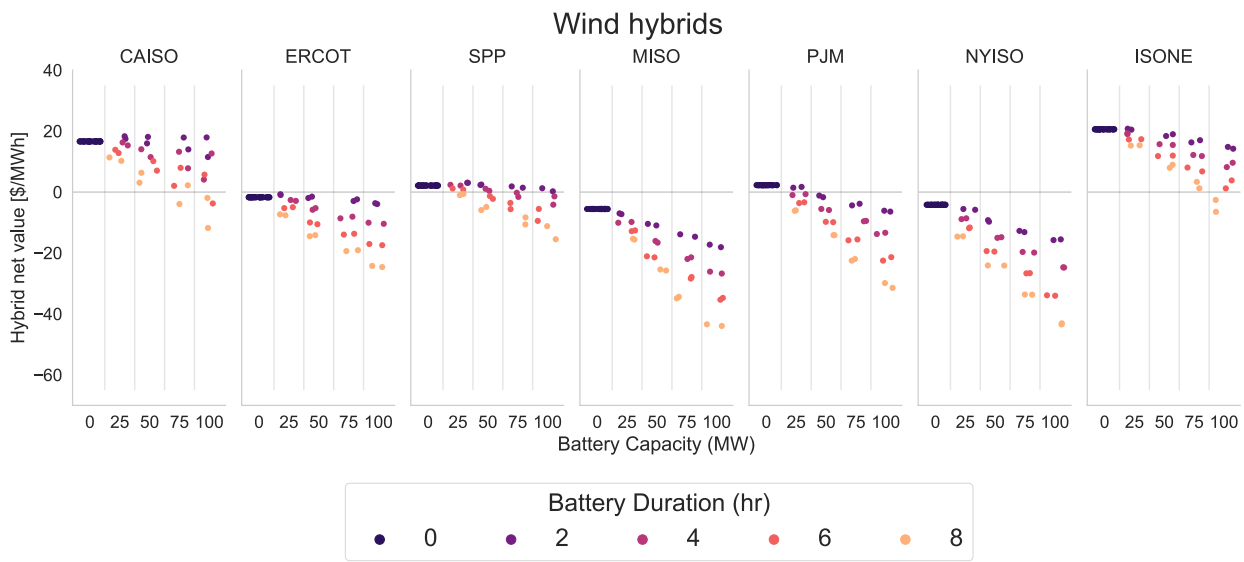


(b)

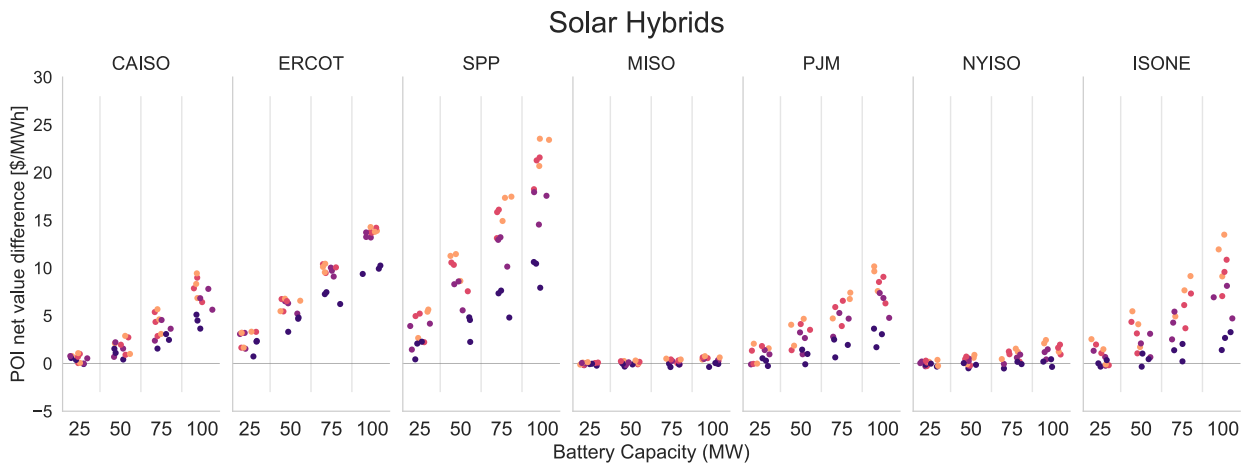
Note: A standalone generator is represented as 0 MW battery capacity with 0 hour duration.

Figure 5. Impact of configuration on (a) solar and (b) wind hybrid net value in the Incentives scenario averaged over 2017-2019.

The remainder of this section examines the configuration choices of point of interconnection capacity, AC vs. DC coupling, and ILR.

For AC-coupled systems, increasing the point of interconnection (POI) capacity to the sum of the capacity of the generator and the battery typically increases the net value relative to the otherwise identical configuration with a lower POI capacity, Figure 6. For ease of exposition, we use the term "POI effect" to refer to the difference in net value between a hybrid configuration with a POI capacity equivalent to the sum of the generator and battery capacity and the net value of the identical configuration except with a POI capacity equivalent to the generator capacity. We find a

relatively limited impact of increased POI capacity for wind hybrids, as in Figure 6, and therefore focus the discussion of the POI effect on solar hybrids.



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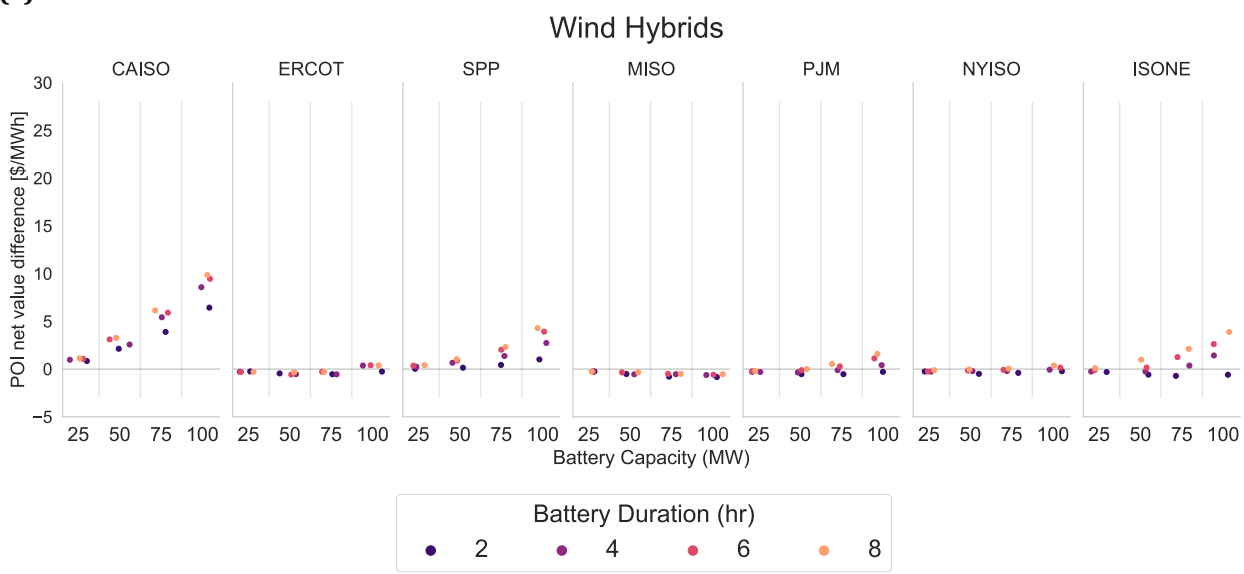

(b)

Figure 6. Impact of increasing the point of interconnection capacity to the sum of battery and renewable generator capacity for (a) solar and (b) wind hybrids averaged over 2017-2019 in the Incentives scenario.

The POI effect increases with larger battery capacity and with longer battery duration. For AC-coupled solar hybrids with 2-hour duration batteries and 100 MW battery capacity in ERCOT or SPP, setting the POI capacity to 200 MW (i.e., the sum of the generator and battery capacity) increases the net value by $8–11/MWh relative to the same hybrid with a POI capacity of 100 MW. These are two regions where peak summer afternoon prices (ERCOT) or high bilateral capacity prices (SPP) are significant contributors to the net value of the solar hybrids. Having extra POI capacity allows solar to produce at full output at the same time that the battery is fully discharging. The POI effect is even larger for batteries with 4-8 hour duration because with longer battery durations there are more time periods where the POI capacity could prevent storage from being fully dispatched simultaneous with high solar production. In SPP, for instance, the POI effect with 8-hour duration batteries can exceed $20/MWh. Even though the POI effect can be large, the

earlier results in Figure 5 show that any of the configurations with 8-hour duration batteries still have a lower net value than hybrids with 2-hour duration batteries, even with higher POI capacity.

Extra POI capacity is relatively less important to the net value of solar hybrids in CAISO where peak prices have shifted toward the early evening, away from times of peak solar production. Further details on how the shifting of the peak period in CAISO impacts the POI effect is shown in Supplementary Note 5 by focusing on the early modeling years (2012-2014), when solar penetration was lower. Interestingly, recent peak prices in CAISO have shifted toward times of higher wind production, making extra POI capacity more valuable for CAISO wind hybrids than wind hybrids in other regions. In regions like MISO, ISO-NE and NYISO, extra POI capacity reduces net value because the increased interconnection cost exceeds the increase in market value. The increase in market value is minimal either because capacity prices are low (e.g., MISO) or because high prices rarely occur at times of high wind production, allowing nearly full discharge of storage at times of high prices, even without extra POI capacity (e.g., ISO-NE).

The last configuration choices, AC vs. DC coupled and ILR, apply solely to solar hybrids and impact the net value by about $5/MWh or less. With the exceptions of ERCOT and SPP, DC coupled configurations have a higher net value that increases with ILR than otherwise similar AC coupled configurations, Figure 7. DC coupling allows battery to capture energy that would otherwise be 'clipped' by the solar generator's AC inverter [44]. As the ILR increases, more and more energy is clipped by an AC coupled system, driving the relative increase in the net value of the DC coupled system.

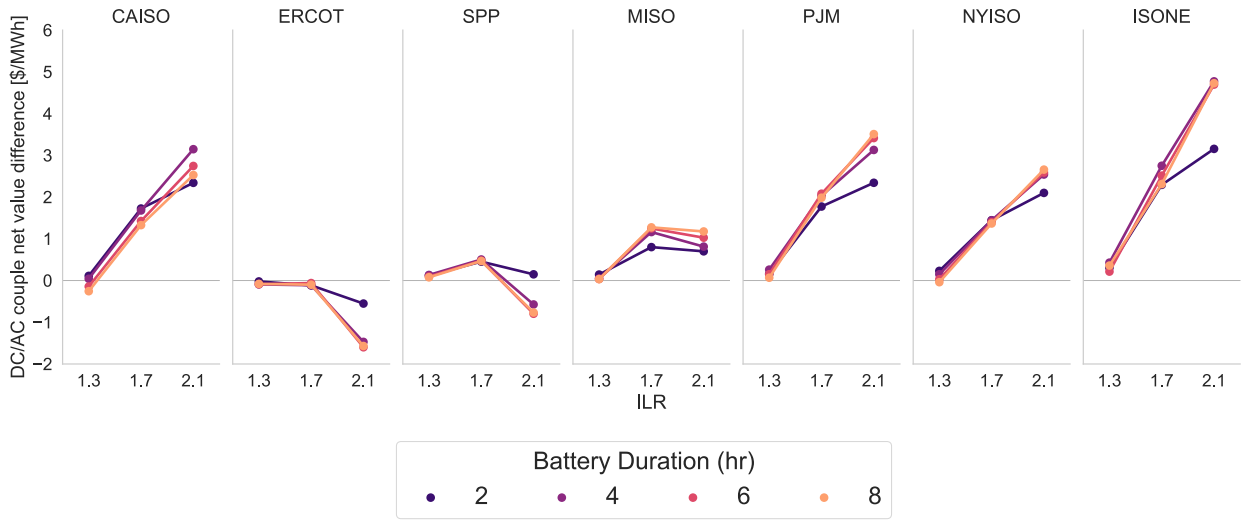

Figure 7. Value difference between DC and AC coupled solar hybrids with 100 MW battery capacity for different ILRs averaged over 2017-2019 in the Incentives scenario.

For DC coupled solar hybrids with 2-hour duration batteries, an ILR of 1.3 has the highest net value in CAISO, ERCOT, and SPP or 1.7 in MISO, PJM, NYISO, and ISO-NE, Figure 8. Higher ILRs increase net value with 4–8 hour duration batteries, though, as discussed earlier, the overall net value of these longer duration configurations is lower than with 2-hour duration.

One surprising finding was that the net value decreased with ILRs larger than 1.3 for 2-hour duration batteries in CAISO, ERCOT, and SPP. Even though market value increases by capturing

otherwise clipped energy, there are additional costs associated with more PV panels and increased battery cycling. The increased cost of the PV panels at higher ILRs is not offset by a corresponding increase in hybrid revenues in these regions. Furthermore, as explained earlier, cycling more energy through storage will not always improve net value depending on the impact to battery lifetime.

In contrast, results in MISO, PJM, NYISO, and ISO-NE show marginal gains when increasing the ILR from 1.3 to 1.7 for DC coupled solar hybrids with 2-hour batteries, though these marginal increases in hybrid net value disappear when the net value is not normalized by the VRE annual generation (see Supplementary Note 6). One hypothesis for the different results between regions are differences in the shape of the net load. Regions with sharply peaking net loads benefit more from power delivered at critical times than from power delivered in other hours. Solar hybrids with higher ILRs deliver more energy overall, but the inverter capacity prevents them from delivering more power at critical times. Regions with smoother net loads, on the other hand, continue to value increased production from otherwise clipped energy, even if it is delivered during non-critical shoulder hours.

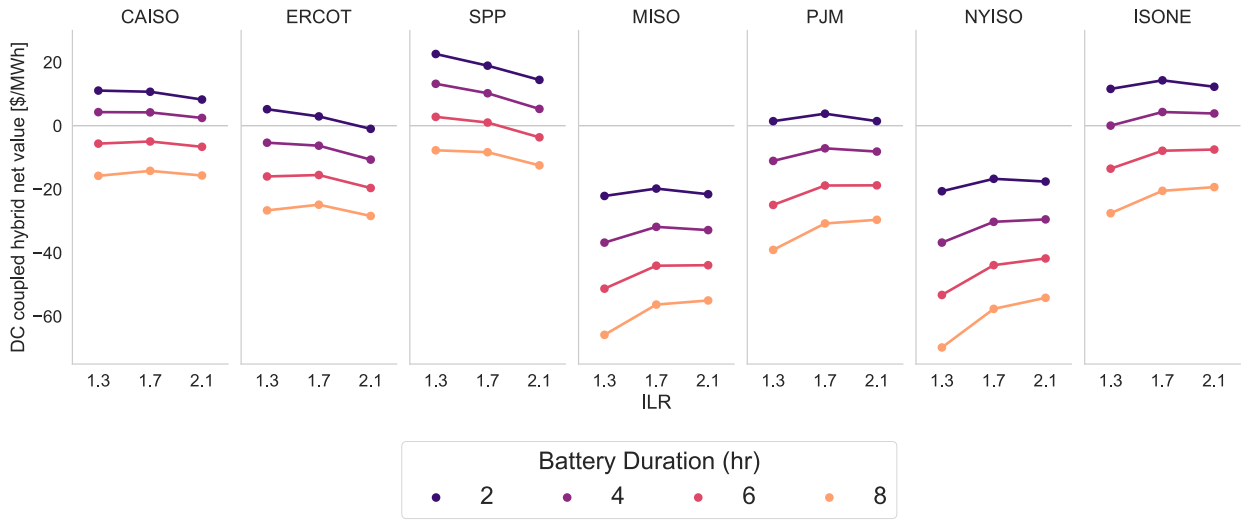

Figure 8. Relationship between net value and ILR for DC coupled solar hybrids with 100 MW battery capacity averaged over 2017-2019 in the Incentives scenario.

Overall, AC vs. DC coupling and ILR configuration choices are secondary considerations[4], in terms of impact to hybrid net value, compared to the choice of battery duration, battery capacity, and POI capacity.

5. Discussion

Comparison of the net value of different hybrid configurations across the U.S. wholesale markets and under a range of scenarios is intended to enhance understanding of recent hybrid configuration decisions made by hybrid developers. One way to gauge the explanatory power of the results is to compare our results to hybrid power plant commercial activity across the U.S. We summarize U.S. hybrid development characteristics from Bolinger et al. [1] based on three different

[4] Small impacts on hybrid net value distributions for different coupling strategies and ILR levels can be seen in Supplementary Note 7.

development stages: (1) deployed hybrids by the end of 2020, Table 4 (2) solar hybrids in the near-term development pipeline that have announced offtake arrangements, Table 5, and (3) solar and wind hybrids that are considered active (as opposed to completed or withdrawn) in interconnection queues, Table 6. This latter source includes many speculative projects because only a small fraction of projects in interconnection queues are ultimately developed [45]. We identify trends in this commercial activity then qualitatively evaluate whether those trends are corroborated by our results.

Table 4. Characteristics of solar and wind hybrid projects deployed across the U.S. at the end of 2020.

	Count	Generator Capacity (MW)	Battery Capacity (MW)	Battery Energy (MWh)	Battery:Generator Capacity Ratio		Battery Duration (hr)	
					Average	Median	Average	Median
Solar Hybrid	73	992	250	658	25%	50%	2.6	2.0
Wind Hybrid	14	1,425	198	122	14%	15%	0.6	0.8

Source: Bolinger et al. [1]

Table 5. Characteristics of solar hybrids that have secured offtake.

	Region	**CAISO**	**ERCOT**	**MISO**	**PJM**	**NYISO**
Solar Hybrid	**Count**	39	11	11	4	6
	Generator Capacity (MW)	5,418	3,358	1,815	215	1,093
	Battery Capacity (MW)	3,203	1,029	624	54	90
	Battery Energy (MWh)	12,173	N/A	2,329	182	360
	Avg. Battery:Generator Capacity Ratio	59%	31%	34%	25%	8%
	Avg. Battery Duration (hr)	3.8	N/A	3.7	3.4	4.0

Source: Bolinger et al. [1]
Note: We aggregate state-level metrics to the corresponding wholesale market region using the following mapping: CAISO = CA; ERCOT = TX; MISO = IN, MO, MS, WI; PJM = KY, NC, VA; NYISO=NY

Table 6. Characteristics of solar and wind hybrid projects active in interconnection queues.

Region			CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Solar Hybrid	Count		150	53	38	62	177	4	35
	Generator Capacity (MW)		41,400	13,050	7,906	9,593	17,228	590	474
	Battery Capacity (MW)		33,838	6,209	3,435	1,238	737	134	-
	Battery:Generator Capacity Ratio	Average	82%	48%	43%	13%	4%	23%	N/A
		Median	99%	40%	40%	25%	32%	15%	N/A
	Additional POI Capacity (% Battery Capacity)	Average	7%	N/A	N/A	N/A	N/A	N/A	N/A
		Median	-1%	N/A	N/A	N/A	N/A	N/A	N/A
Wind Hybrid	Count		9	4	3	0	2	1	0
	Generator Capacity (MW)		4,327	1,015	620	-	390	101	-
	Battery Capacity (MW)		1,779	344	144	-	49	5	-
	Battery:Generator Capacity Ratio	Average	41%	34%	23%	-	13%	5%	-
		Median	99%	32%	28%	-	13%	5%	-
	Additional POI Capacity (% Battery Capacity)	Average	23%	N/A	N/A	N/A	N/A	N/A	N/A
		Median	-3%	N/A	N/A	N/A	N/A	N/A	N/A

Source: Bolinger et al. [1] with more granular regional data derived from [45].
Notes: a – Additional POI capacity is calculated as the POI capacity beyond the generator nameplate capacity as a percentage of the battery nameplate capacity. Negative values imply that the POI capacity is less than the generator nameplate. These values are only reported by the CAISO.

Trend 1: Solar hybrids are more common than wind hybrids. Significantly more individual solar hybrid projects have been developed or are in interconnection queues than wind projects. And although the aggregate generator capacity of online wind hybrids is 30% greater than solar hybrids, there is 26% more battery capacity in the deployed solar hybrids and 5 times as much battery energy in the deployed solar hybrids than the deployed wind hybrids (Table 4). Looking forward, solar hybrids are positioned to dominate even more: aggregate capacity of solar hybrids in the interconnection queues for the seven organized wholesale markets is more than 10 times than that of wind hybrids (Table 6). Our results in the Incentives scenario (Figure 5) back this trend, where the net value of select solar hybrid configurations is on par with or exceeds the net value of standalone solar, indicating solar hybrids are more attractive.[5] In contrast, the net value of wind hybrids is rarely above the net value of standalone wind and far below it in three of the seven market regions. Without the PTC and ITC incentives, the net value advantage of solar hybrids over standalone solar, where there is one, would be similar to the modest net value advantage of wind hybrids relative to standalone wind.

Trend 2: Solar and wind hybrids are most common in CAISO, with substantial commercial activity in ERCOT and SPP. Of all of the wind and solar hybrids in the interconnection queues, nearly 90% of the solar hybrid capacity and 92% of the wind hybrid capacity is in CAISO, ERCOT, and SPP, measured based on the renewable generator capacity (Table 6). Our Incentives scenario (Figure 5)

5 Here we compare only solar hybrids at the same location as the standalone solar. In some regions it may also be important to consider the opportunity cost associated with locating the storage at the solar location, rather than at a location in the grid that is more attractive to storage [27].

similarly shows hybrid net values that are on par with or exceed the standalone net value in CAISO, ERCOT, and SPP. Our results also suggest that solar and wind hybrids in ISO-NE might be marginally attractive relative to standalone. Although we do not see ISO-NE projects with arranged offtakers and few are in the ISO-NE queue, more than 20% of the online solar hybrid projects were in ISO-NE at the end of 2020 [1]. Other analysis suggests this commercial development of solar hybrids in ISO-NE may be driven in part by region-specific incentive programs [46].

Trend 3: Battery durations are typically between 1-4 hours. Deployed solar hybrids have 2–3 hour duration, while deployed wind hybrids have durations shorter than 1 hour (Table 4). Solar hybrids in the near-term development pipeline have durations closer to 4 hours. Our results in the Incentives scenario (Figure 5) show that hybrids with 2-hour duration have the highest net value, though the difference in net value between 2-hour and 4-hour duration is often small in regions where the net value of a hybrid is on par with or exceeds the net value of the standalone generator. Developers may favor 4-hour durations based on expectations that longer duration batteries will become more valuable over the life of the asset, a factor that is not captured in our analysis of historical wholesale market prices.

Trend 4: Battery to generator capacity ratios are larger for solar than wind hybrids and are largest in CAISO. Our results in the Incentive scenario (Figure 5) corroborate this trend. We find that hybrids with 100% battery to generator capacity ratios are the most attractive solar hybrid configuration in CAISO, ERCOT, and SPP. In those same markets, however, the net value of wind hybrids with battery capacity to generator capacity ratios of 25% were nearly the same as wind hybrids with 100% ratios.

Trend 5: Hybrids in the CAISO interconnection queue have a point of interconnection capacity similar to the renewable generator capacity. Here our results disagree with the commercial deployment trends (Table 6): net value is roughly $5/MWh higher for hybrid configurations with the POI capacity set at the sum of the generator and battery capacity rather than just the generator capacity (Figure 6). Reasons for the disagreement may be that (1) actual interconnection costs are higher than our assumption of $\$70/kW_{AC}$, (2) interconnection queue rules make it easier to add storage to a project in the queue without submitting a new queue request as long as the addition does not increase the point of interconnection capacity [47,48], or (3) expectations are that the storage will not need to simultaneously discharge during times of solar production in the future as PV penetrations increase [26].

Trend 6: Limited examples of DC-coupled projects employ ILRs at or above the range of ILRs typical for standalone PV. While the available data are quite sparse, Bolinger et al. [1] summarizes characteristics of 18 DC-coupled projects in the near-term pipeline (the other solar hybrids are either known to be AC-coupled or, in most cases, the coupling is unknown). Only one is in California, 11 are in Hawaii, and the remaining six are in Nevada, New Mexico, and Florida. ILRs of these projects range from 1.3 to 2.8, with ILRs above 1.7 occurring only in Florida or Hawaii. Durations range from 2-8 hours with a median of 4 hours and the median battery to generator capacity ratio is 100%. With the limited examples of DC-coupled projects, it is difficult to draw conclusions from comparisons to our results. One commonality is that the one DC-coupled project in California has an ILR around 1.3, which is also the ILR with the highest net value in CAISO for DC-coupled hybrids with a 100% battery to generator ratio and 2–4 hour duration batteries in the Incentives scenario (Figure 8).

Overall, these qualitative comparisons between our results and commercial hybrid activity, suggest

that analysis of the net value of alternative hybrid configurations can corroborate observed trends and yield insights into how trends may change under different scenarios. This supports the suggestion by Joskow [21] that evaluation of expected costs and wholesale market revenue can be used to understand the relative attractiveness of resource options.

Limitations to the approach do not make this a perfect comparison, however. For example, we use historical observed wholesale market prices, which will differ from expected future prices. Furthermore, our analysis approach begins with dispatching hybrids in response to wholesale prices with a simple linear representation of the costs of cycling, then sequentially evaluates the impact of those dispatch decisions on battery lifetime and ultimately component costs, with a more realistic accounting for non-linear degradation. This is a simplification relative to the approaches tested by Jafari et al. [25] where they holistically evaluate the complex degradation relationships between non-linear degradation, costs, and value in a single optimization. While our hybrid dispatch approach may not be as accurate in dynamically integrating the cycling degradation of the battery, it does allow for separately analyzing cost and value trends, which can be important when each is uncertain but for somewhat unrelated reasons.

In particular, we note that battery component costs and hybridization cost reduction factors are uncertain and rapidly changing, making this analysis most insightful on a relative, rather than absolute, basis. With sparse data on hybridization cost reduction factors, we assumed the factor is the same across our configuration types. This assumption likely makes the configurations with high ILRs and long durations more attractive relative to configurations with low ILRs and short durations given that most hybridization savings come from non-hardware and balance of system costs rather the PV panel and battery pack costs [33]. Even with this potential bias stemming from the unchanging hybridization cost reduction assumption, we find that configurations with low ILRs and short duration batteries are more attractive.

6. Conclusions

We identify attractive solar and wind hybrid configurations across the seven U.S. wholesale power market regions using a framework that compares hybrid market value, based on historical wholesale market prices, to hybrid cost, based on capital costs and battery lifetimes that depend on its utilization. Of the configuration choices considered in this paper, the battery duration and battery capacity have the largest impact on the net value of solar and wind hybrids. Attractive hybrid configurations have two-hour duration batteries, though in many cases there is little difference in net value between 2-hour and 4-hour duration batteries. For solar hybrids, the battery capacity with the highest net value can be either 25% or 100% of the solar generator nameplate capacity, depending on the region, though only the smaller battery capacity is attractive in the absence of the investment tax credit. In contrast, all of the highest net value wind hybrids are those with the smallest battery sized to 25% of the wind capacity with or without the availability of the production tax credit. We find that it is more attractive to set the interconnection capacity to accommodate simultaneous discharge of the generator and the battery, as opposed to limiting the interconnection capacity to the generator power rating, particularly for solar hybrids in the ERCOT and SPP markets. In comparison to all of these configuration options, the choice of AC vs. DC coupling and the sizing of the solar panels relative to the inverter in solar hybrids appear to be secondary. The results of the analysis in terms of hybrid net value, the choice of battery duration, and the sizing of battery capacity all appear to help understand commercial hybrid development activity. On the other hand, developers of solar hybrids in CAISO are choosing smaller point of

interconnection capacity than our analysis would suggest is attractive. Less commercial activity data is available on developer choices for AC vs. DC coupling and the sizing of the PV panels relative the inverter capacity in solar hybrids.

Several future directions could improve this work. First, the battery cost and hybridization cost reduction assumptions are relatively uncertain, yet both are important to the overall economics of hybrids. Future work could refine battery cost and degradation estimates for specific battery technologies, along with incorporating projections of cost trends into the future to make more precise estimates of the net value of specific hybrids. Second, we rely on historical market prices to estimate hybrid market value at single locations within each region. The attractive hybrid configurations may differ in more locations where the transmission system is more congested. There also may be factors outside of the wholesale power markets, such as buyer preferences or other incentive programs, that impact the relative economics of hybrid configurations. Furthermore, as the power system continues to evolve with a changing composition of renewables, storage, and other resources, the market value of hybrids will also change relative to estimates with historical market prices. Improved representation of hybrid configuration options in detailed capacity expansion models could help inform expectations for attractive hybrids.

Credit Author Statement

Cristina Crespo: Conceptualization, Methodology, Software, Data curation, Formal analysis, Visualization, Writing - original draft, Writing - review & editing. **Will Gorman:** Conceptualization, Methodology, Software, Formal analysis, Visualization, Writing - review & editing. **Andrew Mills:** Conceptualization, Methodology, Software, Supervision, Funding acquisition, Methodology, Writing - review & editing. **James Kim:** Data curation, Validation, Writing - review & editing.

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Supplementary Information

Note 1: Additional Details on Hybrid Cost Calculations and Data

Here we provide details on the process for calculating the hybrid costs, which largely builds from NREL's Annual Technology Baseline [36] and PNNL's Energy Storage Cost and Performance Database [37]. We begin by describing the capital cost of the VRE generator and battery, then describe the approach and assumptions for annualizing capital costs, and then finally end with the process for estimating annualized costs of the hybrid resources composed of the VRE generator and battery.

To get to region-specific capital costs, all capital cost data below is scaled by the same regional capital cost multipliers that are used in NREL's ATB, which are derived from previous EIA reports [49].

VRE Generator Capital Cost

Wind capital costs per unit of AC capacity are from NREL's ATB plus an estimate of the interconnection cost. PV capital costs vary with the configuration depending on the inverter loading ratio (ILR). PV plants with a higher ILR purchase more PV panel capacity for the same inverter capacity, leading to the relationship in Eq. 1 for the capital costs per unit of AC capacity.

$$C_{PV} = ILR \cdot C_{PV_field} + C_{PV_inv} + C_{Inter} \quad \text{(Eq. 1)}$$

Table 7. Variable renewable generator capital cost.

Category	Parameter	Value	Unit	Source
Wind Project Capital Cost	C_{wind}	1,494	$/kW$_{AC}$	2019 ATB for Land-based wind in 2020 [36]
Solar Field Capital Cost	C_{PV_field}	1,052	$/kW$_{DC}$	System Advisor Model, with incremental tracking cost from Fu et al. [50]
Solar Power Block Capital Cost	C_{PV_inv}	47	$/kW$_{AC}$	System Advisor Model
Interconnection Cost	C_{Inter}	70	$/kW$_{AC}$	Avg. U.S. interconnection cost [38]

Battery Capital Cost

The capital cost of energy storage per unit of AC capacity is based on the 2020 Lithium Iron Phosphate (LFP) battery technology based on 50 MW battery capacity6 from PNNL [37]. We

6 To get costs for a 50 MW system, we linearly interpolated between costs reported between 10 MW and 100 MW sized systems.

separate capital costs by the battery pack, whose lifetime depends on how the battery is cycled, and the remaining costs of the installed system (we refer to these as the balance of system costs), whose lifetime is independent of cycling.

The capital cost of the pack per unit of AC capacity is the product of the duration (D) and the pack cost in $/kWh, Eq. 2.

$$C_S^{pack} = D \cdot C_E^{pack}(D)$$

(Eq. 2)

The capital cost of the balance of system per unit AC capacity contains elements that depend on the duration and others that do not (Eq. 3). We again add the interconnection cost, except in the configurations where the point of interconnection capacity is not increased.

$$C_S^{bos} = D \cdot C_E^{bos}(D) + C_P^{bos} + C_{Inter}$$

(Eq. 3)

Table 8. Battery capital cost.

Category	Parameter	Unit	Duration			
			2hr	4hr	6hr	8hr
Battery Pack Capital Cost	C_E^{pack}	$/kWh	172.44	170	168.44	167.44
Battery BOS Capital Cost	C_E^{bos}	$/kWh	225	205	198	195
Battery BOS Capital Cost	C_P^{bos}	$/kW	97	97	97	97

Annualization of Capital Costs

Following the default assumptions in NREL's ATB [36] capital costs per unit of AC capacity of component *i* are annualized using a capital recovery factor (*CRF*), adjusted by a project finance factor (*PFF*) that accounts for the post-tax benefits of accelerated depreciation (1.046), and a construction finance factor (*CFF*) for plants that can be built in less than a year (1.014). The capital recovery factor (Eq. 5) is based on the tax rate (26%), a real weighted-average cost of capital (WACC) accounting for taxes (2.71%), and the lifetime of the component (L_i).

$$\underline{C_i} = C_i \cdot CRF_i \cdot CFF \cdot PFF$$

(Eq. 4)

$$CRF_i = \frac{WACC}{1 - \frac{1}{(1 + WACC) \cdot L_i}}$$

(Eq. 5)

Table 9. VRE lifetime and fixed operation and maintenance costs.

Category	Parameter	Value	Unit	Source
Wind Project Lifetime	L_{wind}	30	years	2019 ATB for Land-based wind in 2020 [36]
Solar Project Lifetime	L_{PV}	30	years	2019 ATB for Utility-Scale PV [36]
Battery BOS Lifetime	$L_{S,BOS}$	30	years	Assumed to be the same as used for Solar
Battery Pack Lifetime	$L_{S,pack}$	variable	years	Depends on how battery is cycled
Wind fixed O&M	OM_{wind}	42	$/kW$_{AC}$-yr	2019 ATB for Land-based wind in 2020 [36]
Solar fixed O&M	OM_{PV}	20	$/kW$_{AC}$-yr	2019 ATB for Utility-Scale PV [36]
Battery fixed O&M	OM_S	10	$/kW-yr	Mongird et al. 2019 [51]

For wind and solar, we then scale the annual costs from the annualized capital costs ($\underline{C_{VRE}}$) and fixed operation and maintenance costs (OM_{VRE}), by the nameplate AC capacity of the renewable generator (P_{VRE}), leading to the annual cost of the standalone generator ($/yr).

$$Annual\ Cost_{VRE} = \left(\underline{C_{VRE}} + OM_{VRE}\right) P_{VRE}$$

(Eq. 6)

For storage, we add the annualized capital costs of the pack and the balance of systems to the fixed O&M costs for storage, then scale it all by the nameplate AC capacity of the battery to get the annual cost of the battery ($/yr).

$$Annual\ Cost_S = \left(\underline{C_S^{bos}} + \underline{C_S^{pack}} + OM_S\right) P_S$$

(Eq. 7)

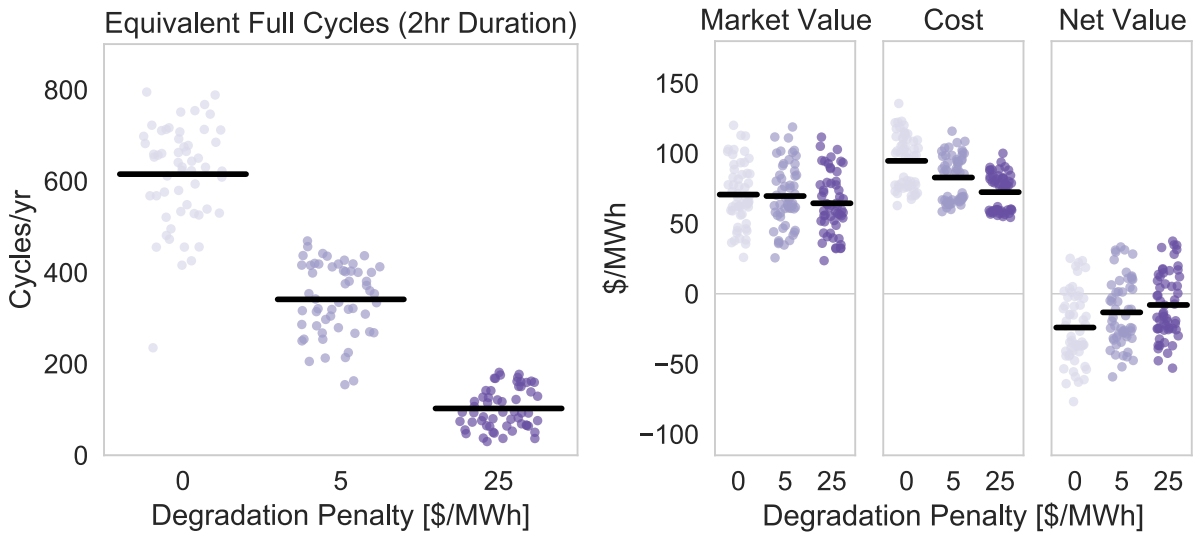
Annualized Hybrid Costs

As described in the main text, scale the sum of the annualized capital cost of the VRE generator and the annualized cost of storage by a hybridization cost reduction factor, *R*, and then add the O&M cost of each component. We estimate the hybridization cost reduction scaling factor to be 6%

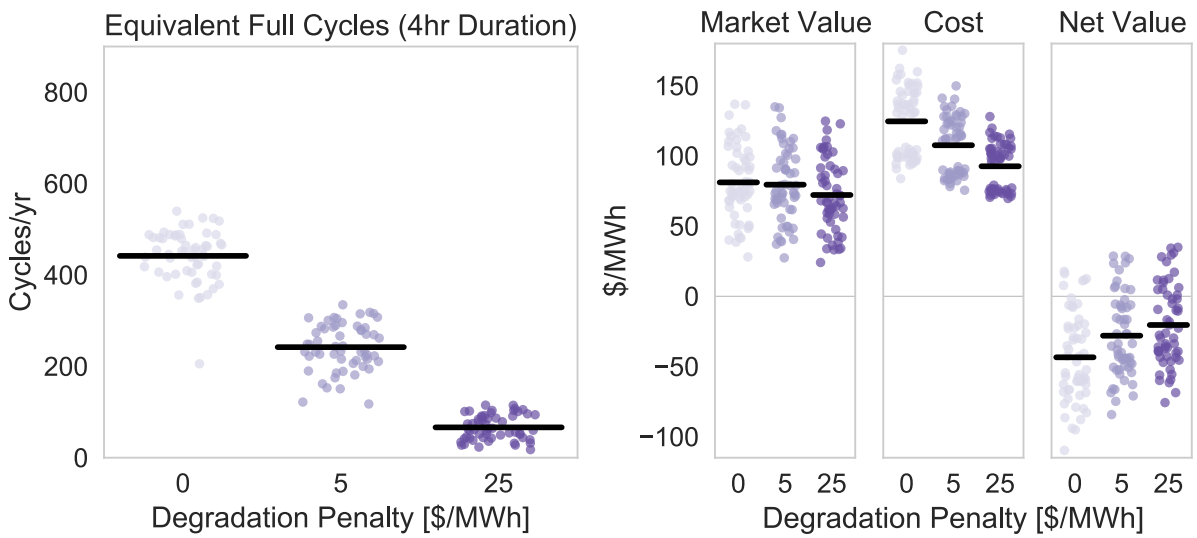
based on the reduction in cost of AC-coupled hybrids reported by Feldman et al. [33] after adjusting for differences in the interconnection cost. We assume the cost reduction factor is the same for DC-coupled hybrids.

Note 2: Impact of Degradation Penalty Assumptions

Here we illustrate the impact of different assumptions for the linear throughput penalty related to degradation costs on the dispatch of the battery, the resulting system value, cost, and net value, Figure 9. We do these calculations for the 1.3 ILR AC-coupled PV system with 100 MW battery capacity, 200 MW POI capacity, and 2 or 4-hour duration. Variations in the estimates, shown by the dots, are due to different regions and different years.



(a)



(b)

Note: Black line shows the average value across all year and region combinations.

Figure 9. Impact of degradation penalty on battery cycles, system value, costs, and net value for solar hybrids with (a) 2-hour and (b) 4-hour duration batteries and 1.3 AC coupled with 100 MW battery capacity and 200 MW POI capacity.

The important point is that the degradation has a large impact on the dispatch and cycling of the battery, but only a small impact on the system value. With a $0/MWh penalty, the battery attempts to capture every arbitrage opportunity, after accounting for losses, even small value opportunities. Increasing the penalty to $5/MWh reduces the number of cycles by half because low value arbitrage opportunities are no longer attractive. Reducing the number of cycles therefore has a limited effect on system value, but a large savings in the annualized cost due to the longer battery life. Higher degradation penalties do start to more substantially impact system value while not reducing cost as much. Therefore, increasing the degradation penalty from $0 to $5/MWh has a bigger benefit to the net value than increasing the degradation penalty from $5/MWh all the way up to $25/MWh.

The impact of the degradation penalty on the storage battery pack lifetime is shown for all configuration-year-region combinations in Figure 10. Based on the assumptions about the calendar life degradation rate, the maximum pack life is 20 years. With a $5/MWh degradation penalty, the battery lifetime is centered around 10 years, depending on the particular way in which the battery is dispatched.

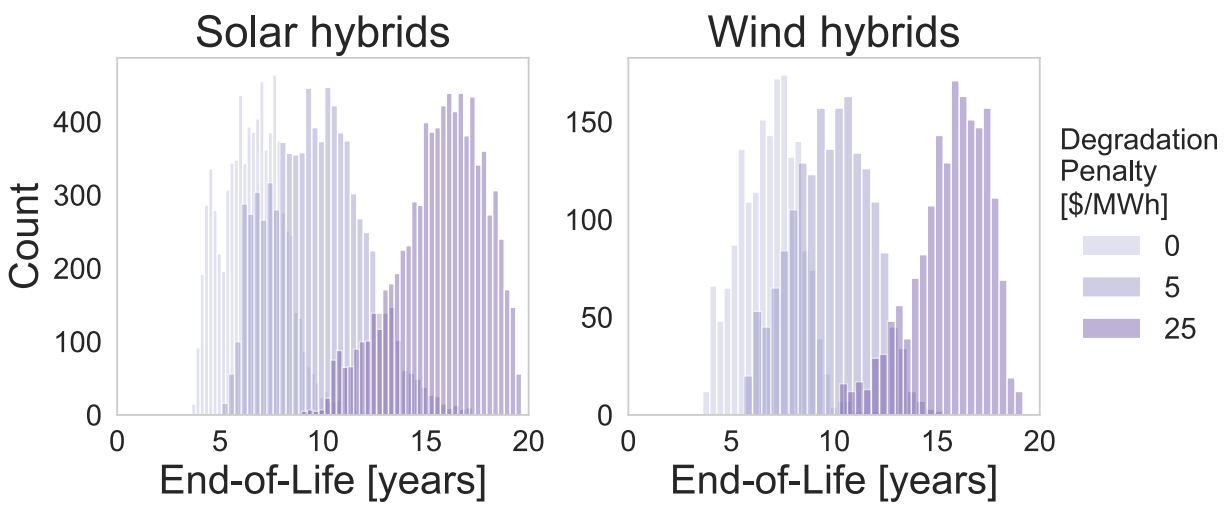
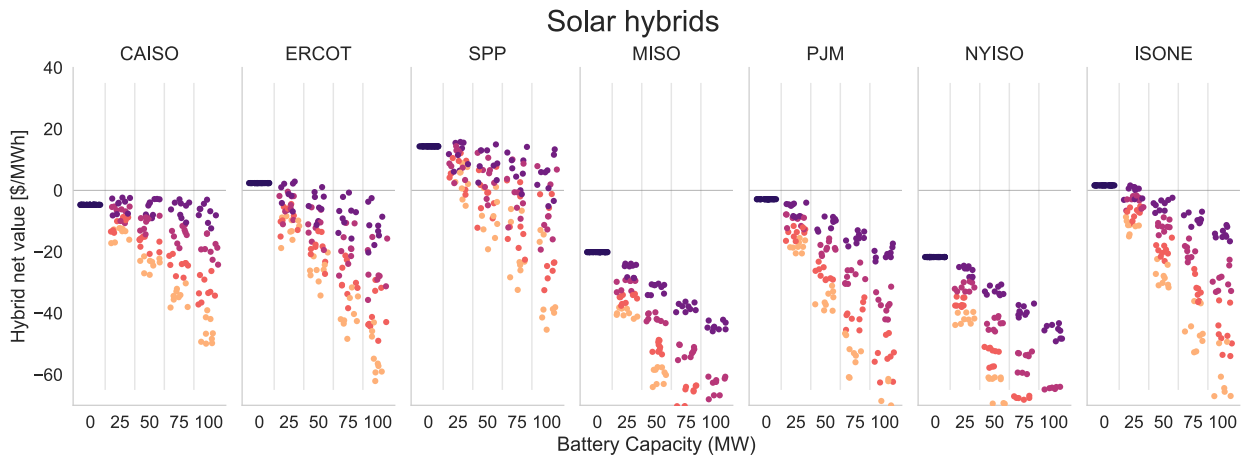


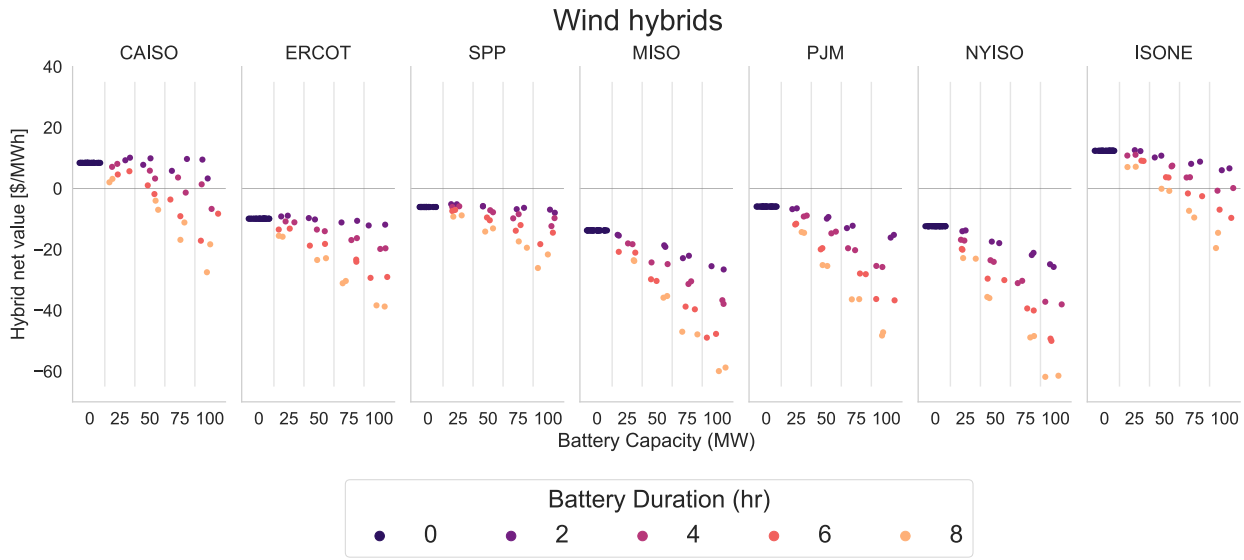
Figure 10. Sensitivity of the lifetime of the battery pack depending on the degradation penalty for all configuration-region-year combinations.

Note 3: Impact of Configuration Choices on Hybrid Net Value in Other Scenarios

Here we show the net value of each configuration averaged across 2017-2019 in the different scenarios other than the Incentive scenario shown in the main text. Note: DEG 0 & DEG 25: Degradation scenarios with $0 and $25 linear throughput penalties; FOR: Imperfect Foresight scenario for hybrid dispatch; NO GC: No Grid Charging scenario; INCT: Incentive scenario which includes ITC/PTC incentives; AS: Ancillary Services scenario allows the battery to provide regulating reserves.

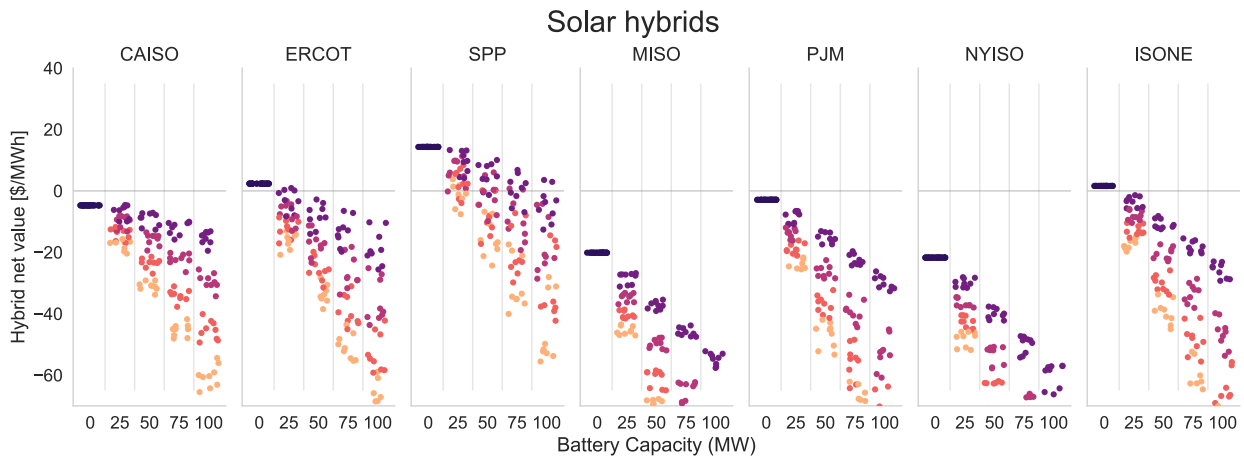


(a)

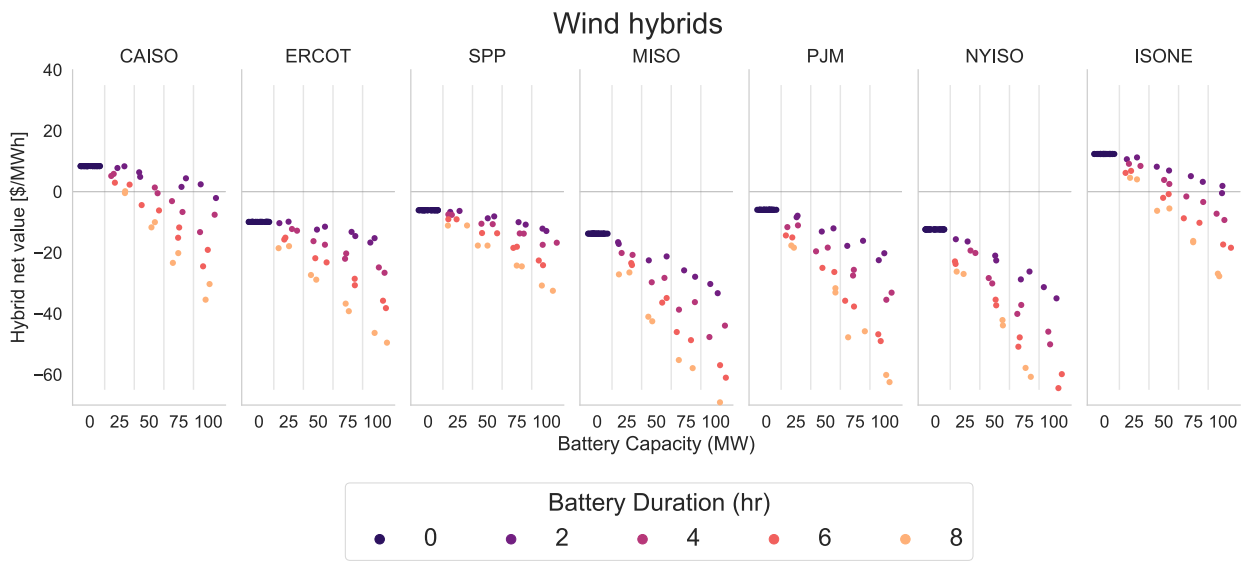


(b)

Figure 11. Impact of configuration on (a) solar and (b) wind hybrid net value in the *BASE* scenario averaged over 2017-2019.

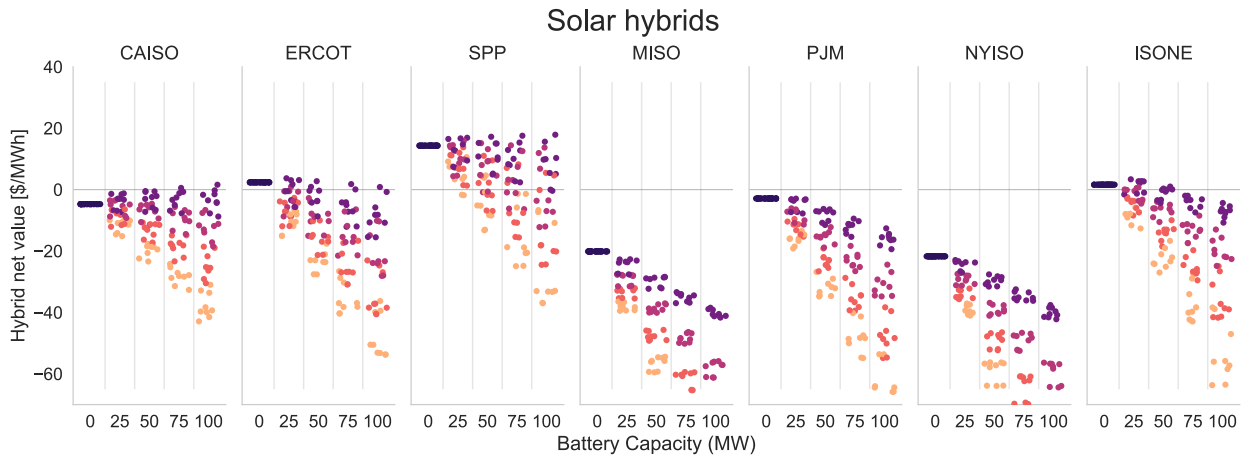


(a)

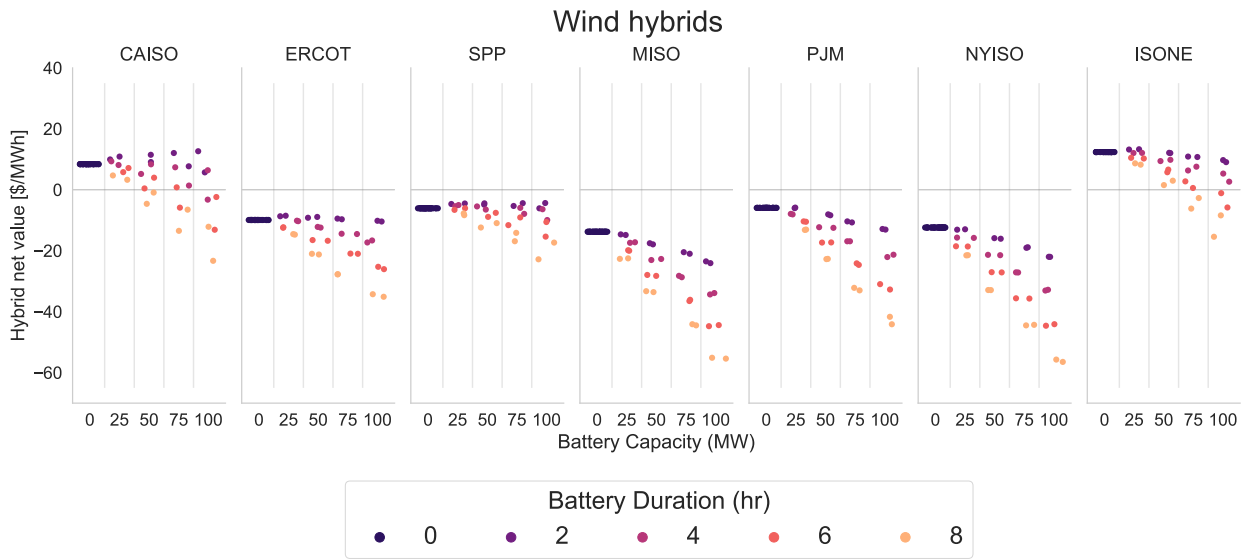


(b)

Figure 12. Impact of configuration on (a) solar and (b) wind hybrid net value in the *DEG 0* scenario averaged over 2017-2019.

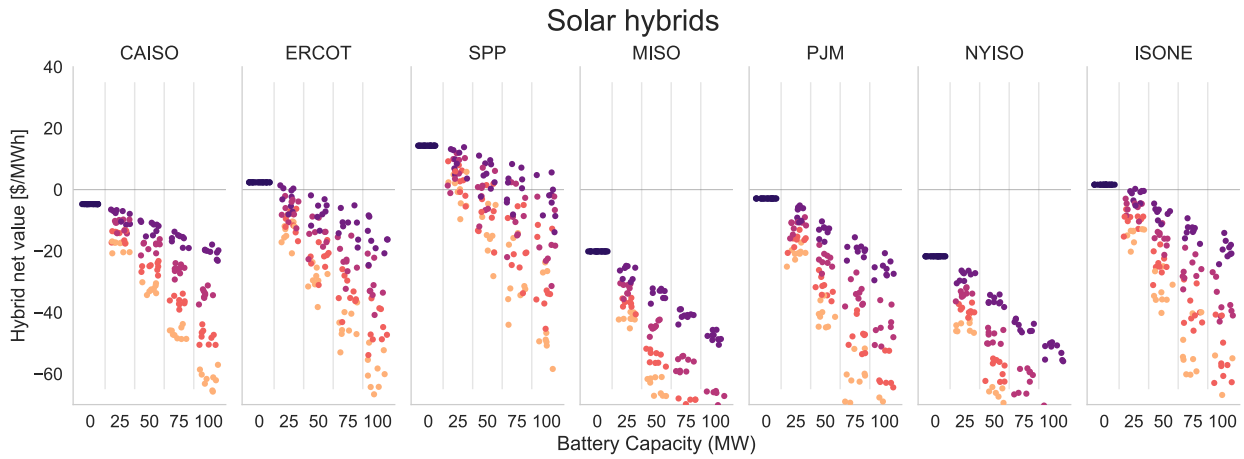


(a)

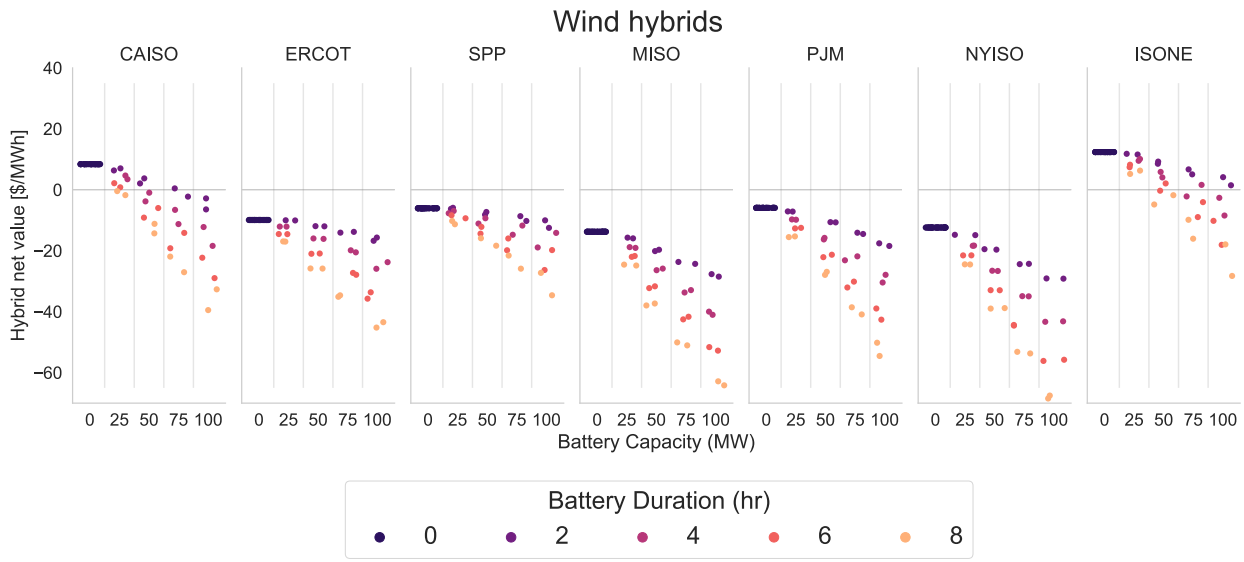


(b)

Figure 13. Impact of configuration on (a) solar and (b) wind hybrid net value in the *DEG 25* scenario averaged over 2017-2019.

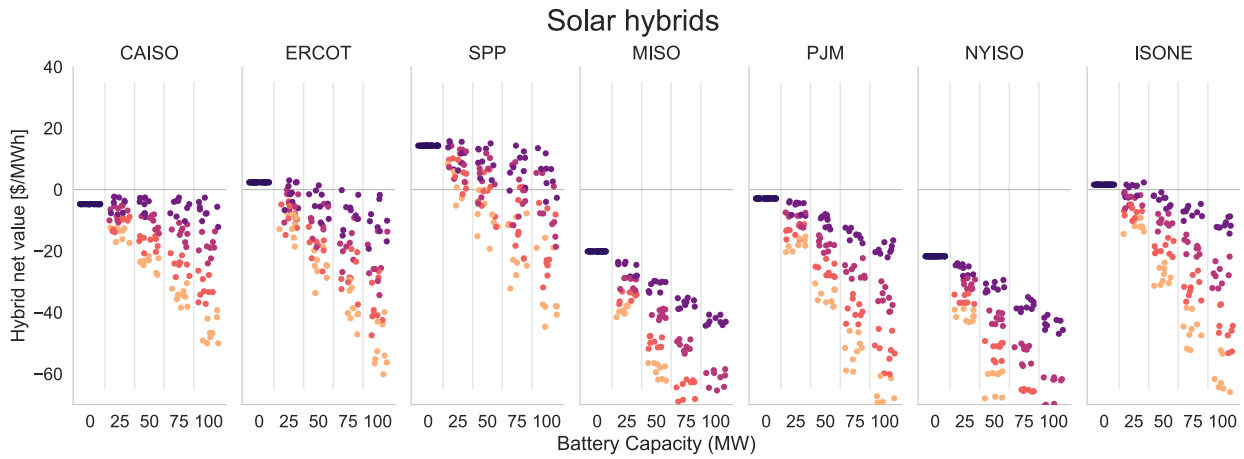


(a)

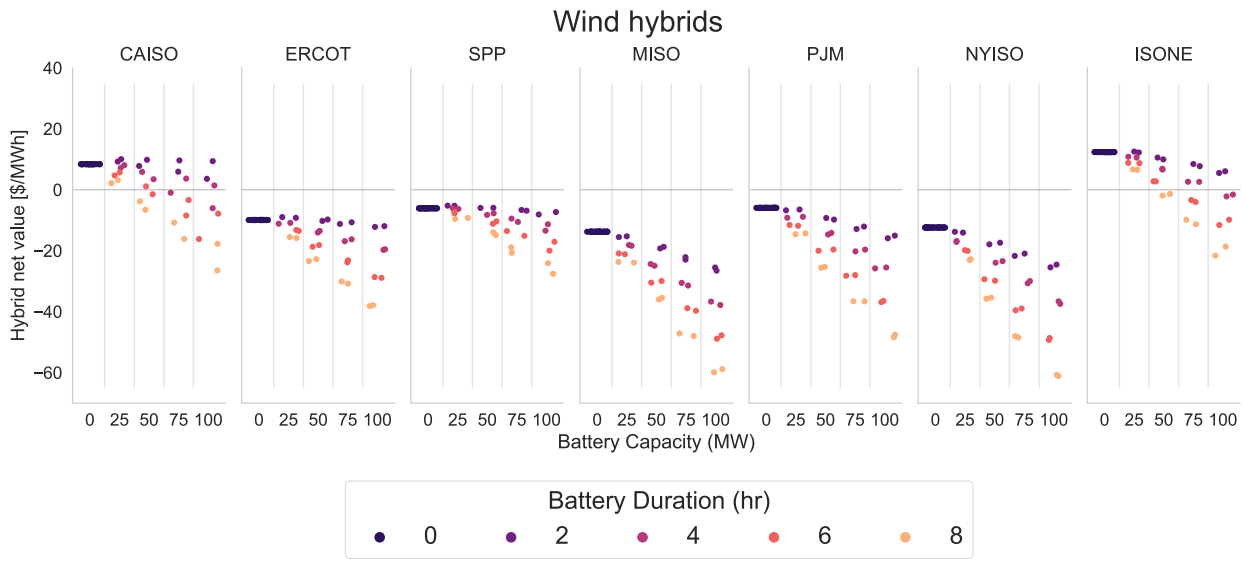


(b)

Figure 14. Impact of configuration on (a) solar and (b) wind hybrid net value in the *FOR* scenario averaged over 2017-2019.

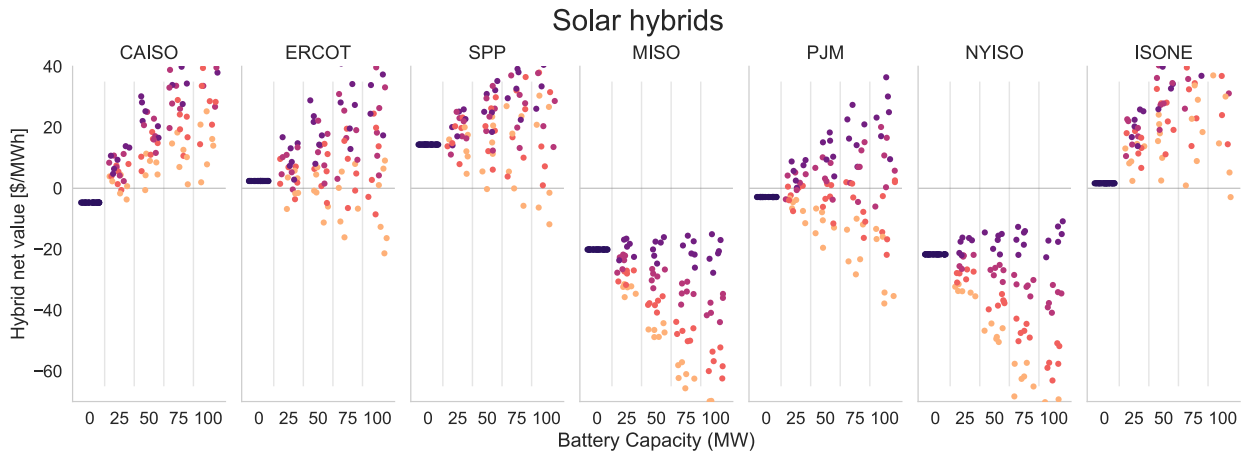


(a)

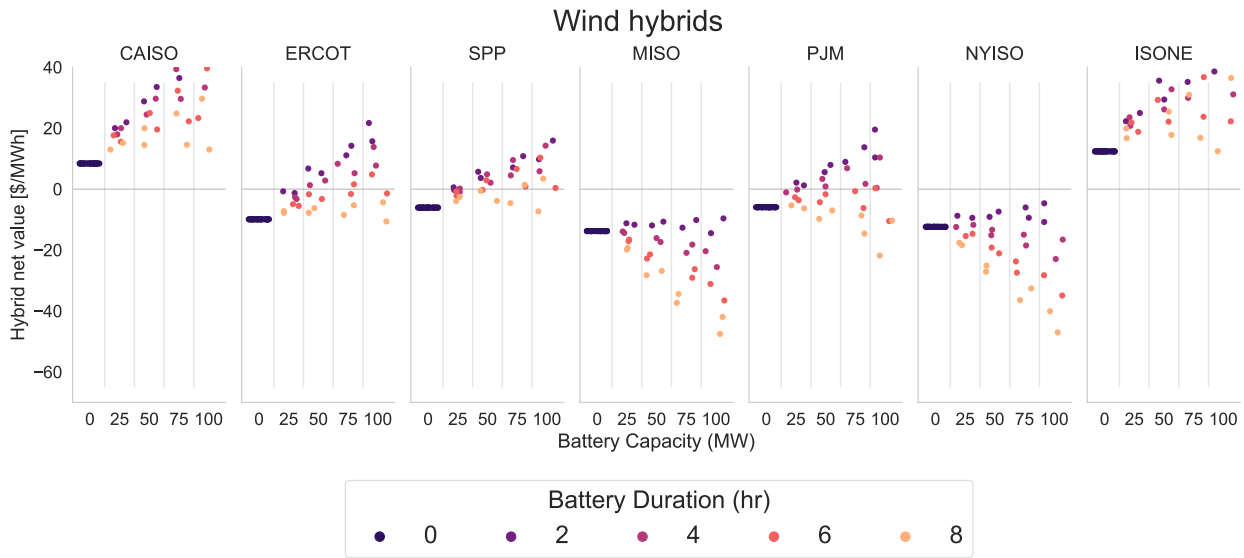


(b)

Figure 15. Impact of configuration on (a) solar and (b) wind hybrid net value in the *NO GC* scenario averaged over 2017-2019.



(a)



(b)

Figure 16. Impact of configuration on (a) solar and (b) wind hybrid net value in the *AS* scenario averaged over 2017-2019.

Note 4: Sensitivity of Findings to Alternative Methods of Calculating Hybrid Cost Reductions

In the main text, we use Eq. 5 to calculate the cost of a hybrid as being less than the cost of the sum of the standalone generator and standalone battery by a hybridization cost reduction factor, R=6%. We estimate R from the literature based on PV-battery with a 1.3 ILR, 4-hour duration battery, with a 0.6 battery to PV capacity ratio. As the battery becomes a smaller component of the overall cost, however, continuing to apply a 6% cost reduction to both the generator and battery cost can bias the cost savings for hybrids with small batteries relative to standalone generators.

An alternative way to model the hybrid cost is to apply all cost reductions to the battery, as in Eq. 8. This alternative formula for the hybrid cost is most useful when considering addition of a small battery to a generator. In place of the original hybridization cost reduction factor, R, we instead rely on an alternative cost reduction factor, R_B, which is only applied to the battery cost component.

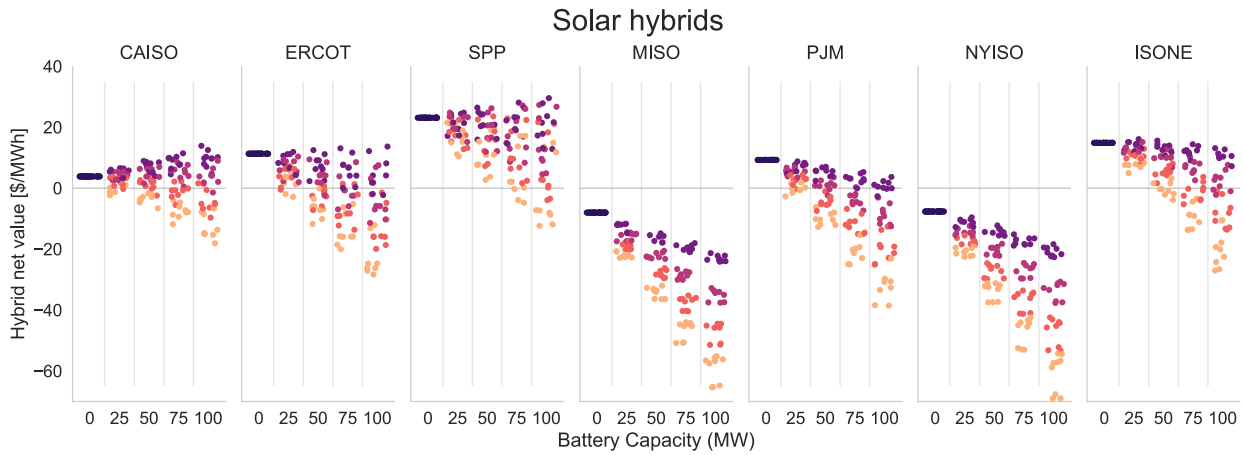
$$Annual\ hybrid\ cost = (C_{VRE} + (1 - R_B)C_B) + (OM_{VRE} + OM_B) \quad \text{(Eq. 8)}$$

A simple relationship between the original cost factor and the alternative that is applied only to the battery, is shown in Eq. 9.

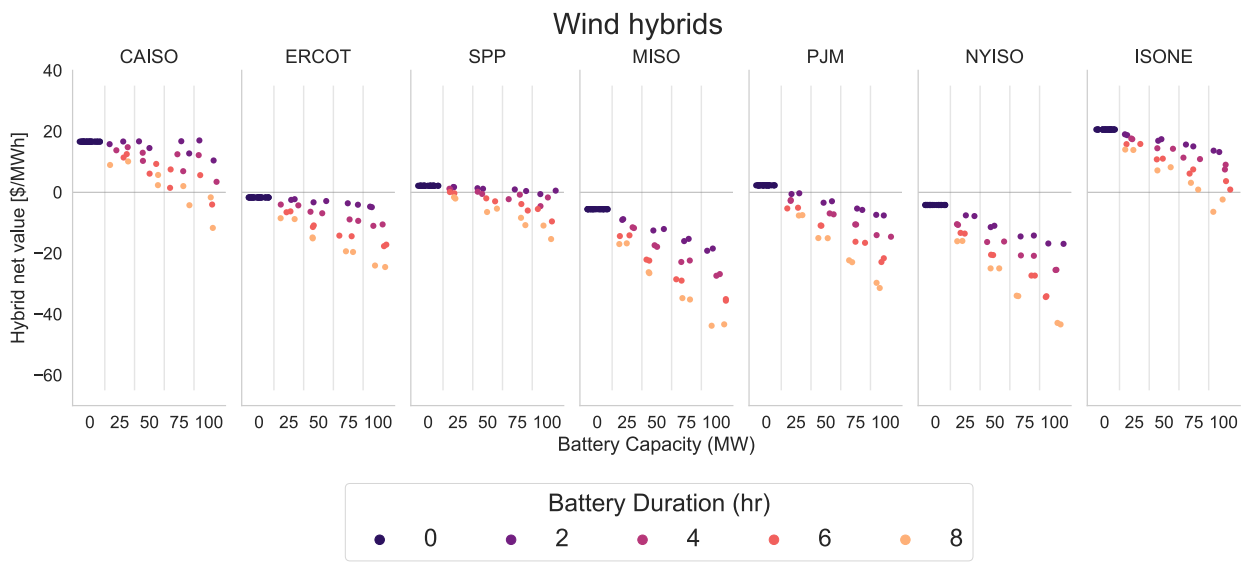
$$R_B = R\frac{C_{VRE} + C_B}{C_B} \quad \text{(Eq. 9)}$$

Using the same source as we used to calculate R, we estimate R_B to be about 10% for AC and DC-coupled hybrids [33].

Here we show the net value of hybrid configurations averaged across 2017-2019 in the Incentive scenario, using the alternative hybridization cost reduction factor, R_B=10%, applied only to the standalone battery cost. Note: Results in the main text use a hybrid reduction factor of R = 6% applied to the standalone generator and the standalone battery costs. From this sensitivity, we conclude that, our primary conclusions do not vary with this alternative modeling approach, though some small 25 MW batteries that were slightly more attractive than the standalone generator are no longer more attractive (e.g., 25 MW solar hybrids in PJM and NYISO, and 25 MW wind hybrids in ERCOT, ISO-NE, and SPP are no longer slightly more attractive than standalone generators).



(a)



(b)

Figure 17. Impact of configuration on solar hybrid net value with R = 3%, in the Incentives scenario averaged over 2017-2019.

Table 10. Maximum solar hybrid net value ($/MWh) with R = 6% (applied to capital costs of both the VRE and batteries) and R_B = 10% (applied only to capital costs of the batteries), in the Incentives scenario averaged over 2017-2019.

[$/MWh]	CAISO		ERCOT		SPP		MISO		PJM		NYISO		ISO-NE	
Battery Capacity (MW)	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**
0	3.9	3.9	11.3	11.3	23.1	23.1	-8.0	-8.0	9.3	9.3	-7.7	-7.7	14.9	14.9
25	8.0	6.6	13.5	11.9	26.3	24.8	-9.5	-11.7	10.9	8.8	-7.2	-9.6	18.4	16.1
50	10.1	8.9	13.8	12.5	27.7	26.5	-12.9	-14.8	8.9	7.0	-10.1	-12.2	17.7	15.6
75	12.4	11.5	14.2	13.1	29.2	28.1	-16.3	-18.0	6.9	5.3	-13.2	-15.2	16.2	14.4
100	14.6	13.9	14.6	13.7	30.4	29.6	-19.8	-21.3	5.1	3.7	-16.7	-18.4	14.7	13.1

Table 11. Maximum wind hybrid net value ($/MWh) with R = 6% (applied to capital costs of both the VRE and batteries) and R_B = 10% (applied only to capital costs of the batteries), in the Incentives scenario averaged over 2017-2019.

[$/MWh]	CAISO		ERCOT		SPP		MISO		PJM		NYISO		ISO-NE	
Battery Capacity (MW)	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**	***R*= 6%**	***R_B*= 10%**
0	16.6	16.6	-1.7	-1.7	2.1	2.13	-5.6	-5.6	2.3	2.3	-4.2	-4.2	20.6	20.6
25	18.3	16.7	-0.7	-2.3	3.1	1.73	-7.0	-8.8	1.7	-0.3	-5.6	-7.6	20.8	19.0
50	18.1	16.7	-1.5	-2.9	2.5	1.33	-10.4	-12.1	-1.2	-3.0	-9.2	-11.0	19.0	17.4
75	17.9	16.8	-2.4	-3.6	1.9	0.93	-13.9	-15.3	-3.8	-5.3	-12.7	-14.2	17.0	15.7
100	17.9	17.0	-3.7	-4.7	1.3	0.53	-17.3	-18.5	-6.1	-7.4	-15.5	-16.8	14.8	13.7

Note 5: Comparison of POI Capacity Effect for Solar Hybrids in 2012–2014 to 2017–2019

The main text shows that point of interconnection (POI) effect for solar hybrids in CAISO across 2017-2019 is smaller than the POI effect for ERCOT and SPP. Here we show that the POI effect was higher in CAISO in 2012-2014 prior to deployment of solar pushing the timing of the net load peaks into the early evening.

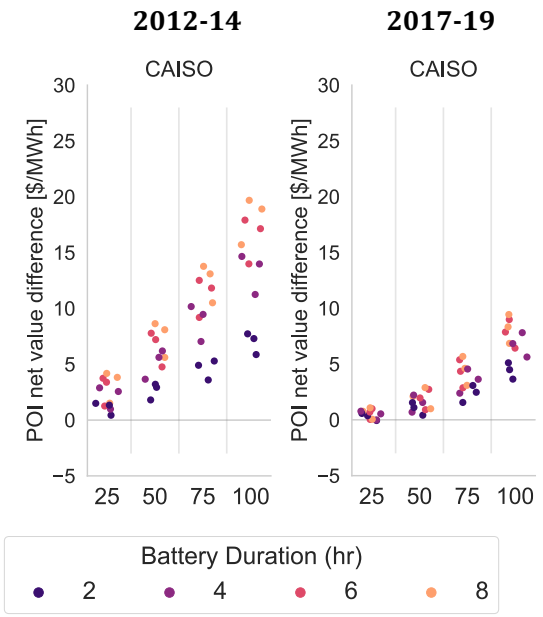


Figure 18. Impact of increasing the point of interconnection capacity for solar hybrids averaged over 2012–2014 compared to 2017-2019 in the Incentives scenario.

Note 6: Additional analysis on the impact of computing a *total* hybrid net value

The main text shows that the effect of different configuration choices on the hybrid net value indicator [$/MWh]. Here we show the sensitivity of some of our results to the use of a *total* hybrid net value indicator [$/yr], not normalized by the VRE annual generation. Figure 19 looks at the impacts of battery duration and capacity on *total* hybrid net value. Figure 20 explores the impacts of ILR for DC coupled solar hybrids on *total* hybrid net value. This analysis demonstrates that the primary conclusions of this paper are not dependent on our choice of denominator for normalizing the net value indicator.

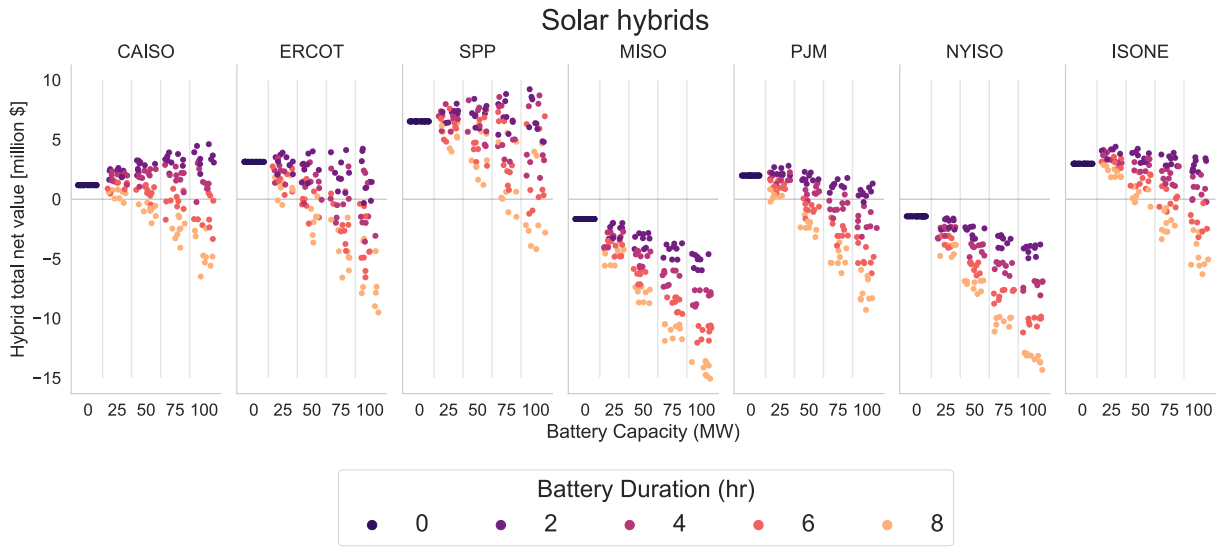


Figure 19. Impact of configuration on solar *total* hybrid net value in the Incentives scenario averaged over 2017-2019.

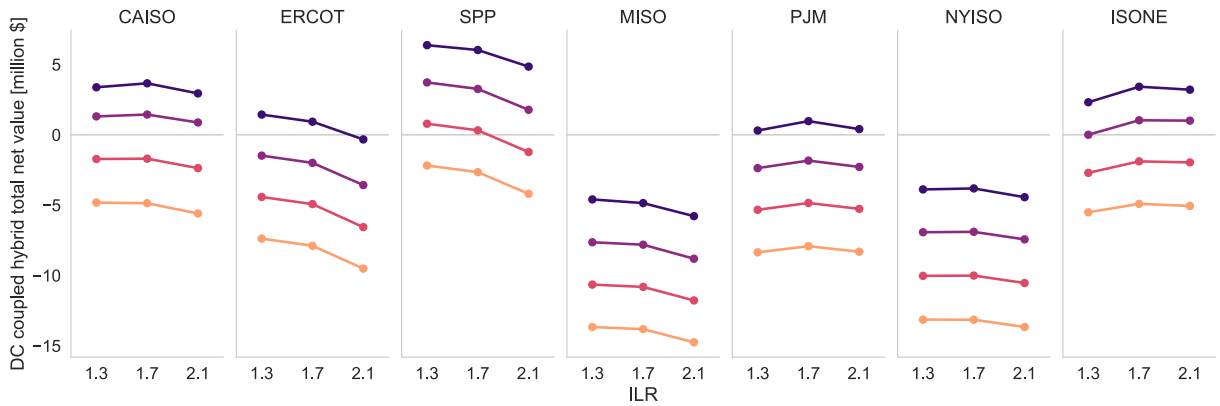


Figure 20. Relationship between *total* hybrid net value and ILR for DC coupled solar hybrids with 100 MW battery capacity averaged over 2017-2019 in the Incentives scenario.

Note 7: Additional Analysis Indicating the Relative Impact of the AC/DC coupling and ILR Choices

The main text shows that the main effects on hybrid net value are due to battery duration and capacity impacts, across 2017-2019 in the scenario with Incentives. In contrast, here we show that the choice of coupling (Figure 21) or inverter loading ration (Figure 22) have a less significant impact on hybrid net value, across 2017-2019 in the scenario with Incentives

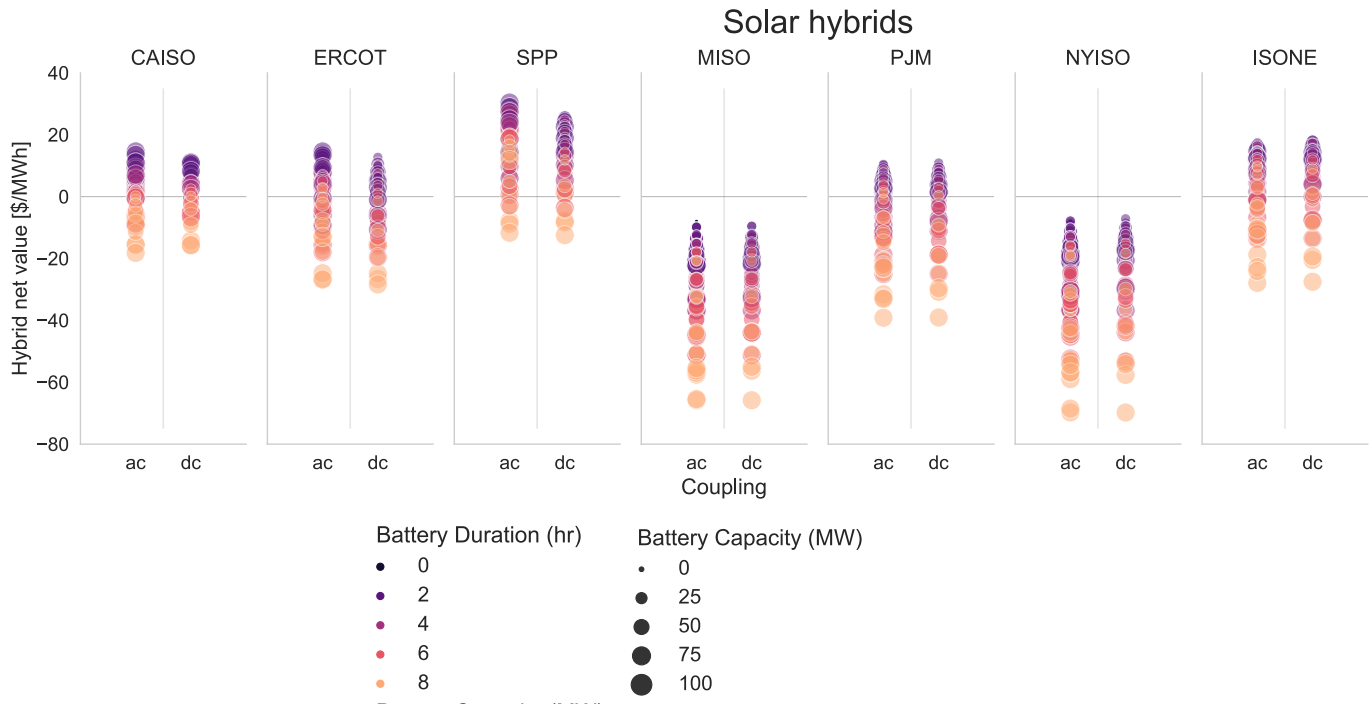


Figure 21. Impact of AC/DC coupling on solar hybrid net value in the Incentives scenario averaged over 2017-2019 across battery duration and capacities.

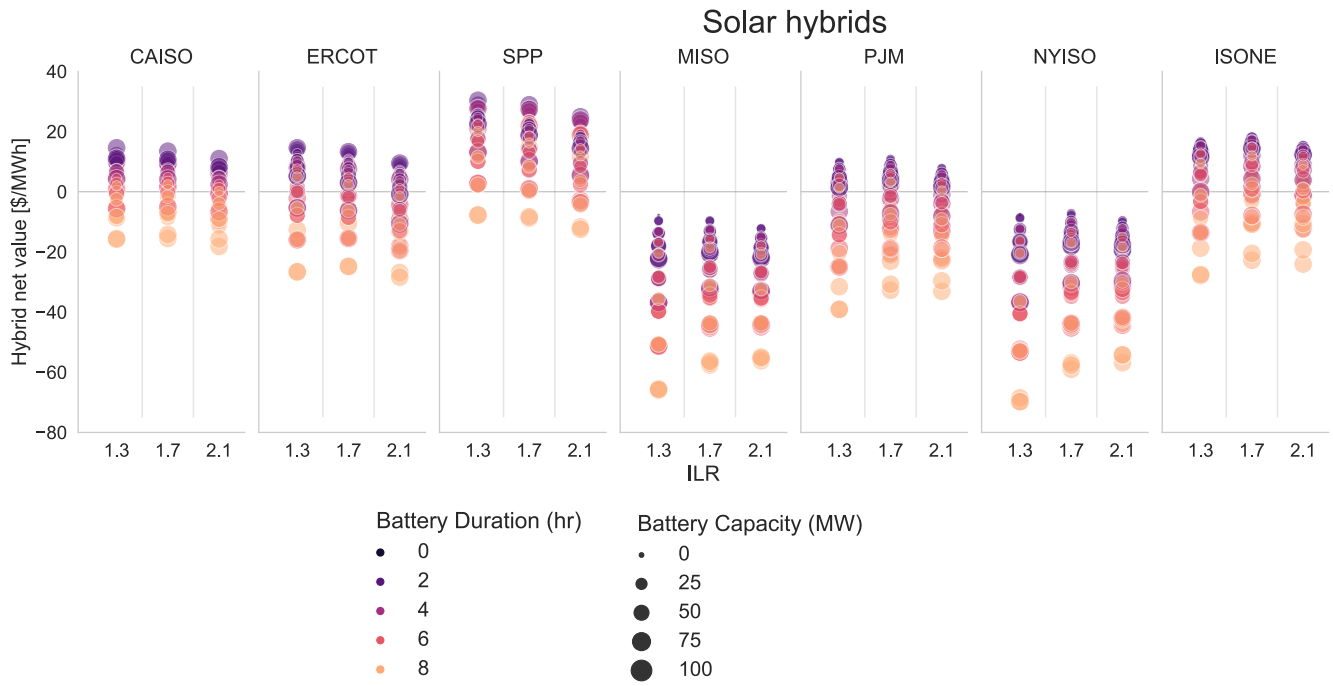


Figure 22. Impact of ILR on solar hybrid net value in the Incentives scenario averaged over 2017-2019 across battery duration and capacities.