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Economic evaluation of variable renewable energy participation in U.S. ancillary services markets

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ABSTRACT

Variable renewable energy (VRE) is not yet meaningfully participating in U.S. ancillary services (AS) markets. VRE participation in AS markets could provide a new source of revenue for VRE resource owners to offset declining energy and capacity values and a new tool for power system operators to address emerging system constraints. This paper uses a price-taker dispatch model and historical prices to estimate the economic value of standalone and hybrid (battery-paired) VRE participation in AS markets, from the resource owner and electricity system perspectives, in each of the seven U.S. independent system operator and regional transmission organization (ISO/RTO) markets where ancillary service prices are set. Across ISO/RTO markets, average (2015–2019) simulated incremental revenues from power regulation market participation were \$0.0–2.9/MWh (+0–15% of revenue without participation) for standalone VRE owners and \$1–33/MWh (+1–69%) for hybrid VRE owners. However, ISO/RTO reserve markets are relatively thin and have the potential to become saturated by energy storage projects that are currently in ISO/RTO interconnection queues. In most markets, standalone and hybrid VRE could provide power regulation reserves during periods with high power regulation prices, suggesting that VRE participation in AS markets could have high system value. The analysis highlights the relevance of separate upward and downward power regulation products and indicates that ISOs/RTOs might consider initially focusing on enabling hybrid VRE provision of AS.

1. Introduction

Variable renewable energy (VRE) participation in ancillary services (AS) markets could provide new sources of value for resource owners and new options for system operators to manage grid reliability.[1] From the perspective of VRE resource owners, AS market revenues could help offset expected energy and capacity value declines as VRE penetrations increase (Mills and Ryan, 2013; Seel et al., 2018; Millstein et al., 2021). From the perspective of system operators and the electricity system, VRE participation in AS markets could provide lower-cost reserve capacity and additional tools for relieving unit commitment and ramping constraints.

VRE is technically able to provide essential reliability services, including power regulation and contingency reserves (Ela et al., 2014; Loutan et al., 2017, 2020; Rebello et al., 2020), but there has been limited to no analysis of participation models, economic value, and barriers for VRE participation in U.S. electricity markets. Several studies have shown that wind generators can increase their revenues by providing power regulation reserves (Troy and Twohig, 2010; Liang et al., 2011; Rebello et al., 2020) and that changes in market rules may be needed to remove barriers to VRE participation in AS markets (Holttinen et al., 2016; Fernandes et al., 2016), though these studies have focused on European electricity markets or generalized electricity systems. Wind generation is participating in power regulation markets in the United Kingdom, and reserve markets in Spain (Edmunds et al., 2019), but VRE participation in U.S. AS markets is currently low or nonexistent.

This paper addresses three main questions about VRE participation in U.S. AS markets. First, what are the participation models (Section 2.1.1) and economic principles (Section 2.2.2) underpinning VRE

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[1] This paper focuses on onshore wind and solar photovoltaic (PV) technologies, though some of the conclusions and discussion would apply to run-of-river hydropower and offshore wind power as well.

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Table 1
Current (2020) ISO/RTO reserve products and procurement practices.

ISO/RTO	AS Reserve Products	Procurement Practices	AS Price Cascading
CAISO	Power regulation up, power regulation down, spinning, non-spinning	Co-optimized procurement of energy, power regulation, and spin/non-spin procurement in day-ahead and 15-min markets	Power regulation price ≥ spinning price ≥ non-spinning price
ERCOT	Power regulation up, power regulation down, responsive, non-spinning	Co-optimized procurement of energy, power regulation, responsive, and non-spinning reserves in the day-ahead market; intraday procurement of additional reserves in supplemental AS market (SASM); no real-time market co-optimization (ERCOT is currently developing real-time co-optimization)	Responsive price ≥ non-spinning price
SPP	Power regulation up, power regulation down, spinning, supplemental	Co-optimized energy, power regulation, and operating reserve procurement in day-ahead and real-time markets	Power regulation price ≥ spinning price ≥ supplemental price
MISO	Power regulation, spinning, supplemental (MISO is currently developing a separate short-term reserve product)	Co-optimized energy, power regulation, and operating reserve procurement in day-ahead and real-time markets	Power regulation price ≥ spinning price ≥ supplemental price
PJM	Power regulation, scheduling, primary (synchronized, non-synchronized), supplemental (no market)	Scheduling reserves procured day-ahead but not maintained in real-time; co-optimized hourly procurement of energy and primary reserves, separate hourly power regulation procurement (PJM is currently developing day-ahead and real-time co-optimization for all reserves)	Synchronized price ≥ non-synchronized price
NYISO	Power regulation, 10-min spinning, 10-min non-synchronized, 30-min spinning, 30-min non-synchronized	Co-optimized energy, power regulation, and operating reserve procurement in day-ahead and real-time markets	10-min spinning price ≥10-min non-spinning price ≥30-min operating price
ISO-NE	Power regulation, 10-min spinning, 10-min non-spinning, 30-min operating	Six-month-ahead but no day-ahead procurement; co-optimized real-time energy and operating reserve procurement; separate real-time power regulation procurement (ISO-NE is currently developing day-ahead reserve procurement)	10-min spinning price ≥10-min non-spinning price ≥30-min operating price

Notes: ERCOT's responsive reserves and PJM's primary synchronized reserves are spinning reserves. SPP and MISO's supplemental reserves and PJM's and NYISO's non-synchronous reserves are non-spinning.
Sources: This information is based on a review of ISO/RTO tariffs and manuals. See CAISO (2021); Electric Reliability Council of Texas (2020); Southwest Power Pool (2020); MISO (2020); PJM (2021); NYISO (2019); Independent System Operator – New England (2021). Price cascading information is also based on Giacomoni et al. (2018).

participation in U.S. AS markets. Second, what is the value to resource owners (Sections 4.1 and 4.2) and the electricity system (Section 4.3) of VRE participation in AS markets, and how would sensitivities around interconnection limits, provision of different AS products, and market prices affect the results (Section 4.4). Third, and more qualitatively, how might AS market participation barriers (Section 5.1), changes in AS market volumes and pricing (Section 5.2), and changes in market design and AS products (Section 5.3) affect the results.

The economic analysis uses a price-taker dispatch model with simple, consistent assumptions that facilitate comparisons across technologies, VRE configurations, and markets over time. This framework differs from an equilibrium model, which typically endogenizes prices and accounts for the strategic behavior of market participants (Rodríguez-Sarasty et al., 2021). It considers two kinds of VRE configurations: (1) standalone VRE facilities with a standalone solar or wind facility; and (2) hybrid VRE facilities with a solar or wind facility paired with battery storage. In a base case, the analysis focuses on VRE participation in power regulation markets using historical market prices, with interconnection capacity limits sized to the VRE facility's nameplate capacity. It also examines sensitivities in which interconnection capacity limits are sized to the maximum output of the combined generator and battery capacity (for hybrids), VRE participates in spinning reserve markets, and VRE participates in future power regulation markets in electricity systems with higher renewable penetration.

The price-taker assumption and the use of historical prices are key limitations of the analysis, though they incorporate elements of market behavior that are not easily captured in market price forecasts. Section 4.4 examines the sensitivity of the results to energy and AS prices in future markets that have higher levels of VRE and storage. Section 5.2 qualitatively discusses how VRE and energy storage participation in AS markets might affect market prices and the results.

2. Background

2.1. Key differences in ISO/RTO AS markets

U.S. independent system operators (ISOs) and regional transmission organizations (RTOs) procure six AS products: power regulation reserves, spinning reserves, non-spinning reserves, ramping reserves, voltage support, and black start capability. ISOs/RTOs procure power regulation, spinning, and non-spinning reserves through competitive markets, and voltage support and black start capability bilaterally on a cost basis. CAISO and MISO procure ramping reserves using constraints in market software. This paper focuses on the highest-value AS products procured through competitive markets across all ISO/RTO markets: power regulation and spinning reserves (Ela et al., 2019).

ISOs/RTOs differ in their definitions of competitively procured AS products, in how they procure different products, in their AS market designs, and how prices are formed in their AS markets. Some of these differences are important for understanding our assumptions and results. This section provides an overview of key differences among ISO/RTO AS markets that are relevant to this analysis. For more in-depth reviews of ISO/RTO AS markets, see Ellison et al. (2012), Zhou et al. (2016), and Ela et al. (2019).

Table 1 describes differences in three aspects of ISO/RTO AS markets relevant to this analysis: AS reserve products, procurement practices, and AS pricing. As Table 1 indicates, ISOs/RTOs are continuing to adjust their AS market designs. Regarding AS products, a key distinction among ISOs/RTOs is in their procurement of power regulation reserves. CAISO, ERCOT, and SPP procure upward and downward power regulation reserves separately, whereas the other four ISOs/RTOs procure power regulation reserves as a bi-directional product. In the latter case, resource-providing power regulation reserves must hold equal reserve capacity in the upward and downward directions.

In terms of AS procurement practices, ISOs/RTOs can be grouped into three main categories: (1) co-optimized energy and all reserve procurement in day-ahead and real-time markets (CAISO,[2] MISO, NYISO, SPP), (2) no day-ahead co-optimization and co-optimized energy and operating reserve procurement in hour-ahead scheduling processes and real-time markets (ISO-NE, PJM), and (3) day-ahead but no real-time co-optimization (ERCOT).[3] ISOs/RTOs with day-ahead and real-time AS co-optimization (CAISO, MISO, NYISO, SPP) have two-settlement systems, meaning that real-time AS market settlement is incremental to day-ahead AS market settlement. ISOs/RTOs that do not (ERCOT, ISO-NE, PJM) have single-settlement systems for AS.

In terms of AS pricing, the nature of price cascading differs among ISOs/RTOs. Price cascading refers to the nesting of reserve constraints, so that higher value reserves can substitute for lower value ones and that prices for higher value reserves will always be greater than or equal to lower value ones. In CAISO, MISO, and SPP, power regulation prices will always be greater than or equal to spinning and non-spinning reserve prices, whereas in ERCOT, ISO-NE, NYISO, and PJM, spinning reserve prices can exceed power regulation prices.[4] CAISO and NYISO also have AS price cascading across load zones based on transmission constraints, which means that AS prices in more constrained zones will be greater than or equal to prices in less constrained zones.[5]

Driven partly by these differences in procurement practices and market design and partly by differences in load profiles and generation mixes, AS prices and price volatility vary significantly across ISOs/RTOs. ISOs/RTOs procure AS zonally and AS prices are zonal rather than nodal. Fig. 1 illustrates AS price differences, showing average zonal power regulation prices from 2015 to 2019 used in this analysis.[6] Fig. 1 also illustrates the significant year-to-year variation in power regulation prices, which holds for other reserves as well. Interannual variability results from energy price volatility, changes in supply-demand conditions, hydro availability, and changes in AS procurement and market design. For instance, the spike in upward power regulation prices in ERCOT in 2019 resulted from high demand, which drove tight supply conditions (Potomac Economics, 2020). The increase in power regulation prices in CAISO between 2015 and 2016–2019 was driven by an increase in power regulation procurement by the CAISO starting in 2016, along with growing challenges with procuring downward power regulation reserves from conventional sources (Mills et al., 2021).

Our approach (see Section 3) attempts to capture these differences in AS products, procurement and market design among ISOs/RTOs. Differences in AS prices among ISOs/RTOs have a significant impact on the results (see Section 4).

2.2. VRE participation in AS markets

Studies and demonstration projects over the late 2000s and 2010s showed that, from a technical perspective, solar and wind facilities could be integrated into economic dispatch (NYISO, 2010) and provide essential reliability services (Kirby and Milligan, 2009; Ela et al., 2014; Milligan et al., 2015; Loutan et al., 2017, 2020; Rebello et al., 2020). Standalone VRE has been integrated into system dispatch in all ISO/RTO markets but, to our knowledge, is not yet meaningfully providing frequency regulation or spinning reserves in any of them.[7] Most ISOs/RTOs have not yet implemented rules for hybrid VRE participation in AS markets.[8]

2.2.1. Participation models

Participation models for VRE resources in AS markets depend on ISO/RTO market designs and, in real-time markets, on whether resources are standalone or hybrid. For ISOs/RTOs with day-ahead and real-time AS co-optimization (CAISO, MISO, NYISO, SPP) or for day-ahead scheduling reserves in PJM, VRE participation in day-ahead AS markets would be financial rather than physical and would affect physical operations primarily through system operator unit commitment decisions.

For example, if a standalone solar PV facility is selected to provide 10 MW of upward power regulation reserves between 14:00 and 15:00 at a day-ahead power regulation clearing price of \$20/MW, but only has sufficient energy to provide an average of 5 MW in real-time during part of this interval (e.g., 14:05–14:10) when real-time power regulation prices are \$30/MW, the PV facility buys back 5 MW of its day-ahead reserve provision at an equivalent of \$10/MW. The system operator could reduce its day-ahead commitment of non-VRE resources by an average of 10 MW in that hour, but through its day-ahead or intraday commitment processes, the system operator would need to ensure that it can make up any reserve shortfall, or in this case an additional 5 MW.

VRE provision of reserves in real-time markets would be physical rather than financial. VRE would be paid for providing the reserve product and for power regulation energy and contingency dispatch energy,[9] which is settled at locational marginal prices (LMPs), and would face penalties for non-performance. For standalone VRE, provision of upward power regulation and spinning reserves would require curtailment of 5-min forecasted generation, though the provision of upward power regulation energy and contingency dispatch energy would provide an additional revenue source. Standalone VRE provision of downward power regulation reserves would not require curtailment of real-time forecasts, though the provision of downward power regulation energy and corresponding reduction in energy generated would reduce revenues.

For instance, a standalone solar PV facility providing 10 MW of upward power regulation reserve in the 14:10:00 to 14:15:00 interval would have this 10 MW curtailed in that interval through real-time economic dispatch, which means that it must have had at least a 10-MW forecast, plus a statistically determined buffer, as of its 5-min forecast when real-time dispatch is run (e.g., 14:00:00 or 14:02:30). If the power regulation up clearing price is \$30/MW, the energy price (real-time LMP) is \$25/MWh, and the facility provides 50 MWh of energy and 2 MWh of power regulation energy (hourly equivalent), its total settlement in that interval will be \$133 (= [10 MW × \$30/MW +

[2] CAISO co-optimizes procurement in its 15-min but not its 5-min real-time market. CAISO is the only ISO/RTO with a 15-min market.

[3] As noted in the table, ERCOT is currently developing real-time energy and AS co-optimization.

[4] For instance, for the zonal prices used in this analysis, day-ahead spinning reserve prices exceeded day-ahead power regulation up prices in more than 90% of hours in ERCOT in 2018; in ISO-NE and PJM, real-time spinning reserve prices exceeded power regulation prices in 1% and 3% of hours, respectively, in 2018.

[5] In CAISO, cascading runs from sub-regions to the system region to the expanded system region (sub-regions ≥ system region ≥ expanded system region). In NYISO, cascading runs from the Long Island (LI) zone to the Southeastern New York (SENY) zones to the East of Central-East (EAST) zones to the New York Control Area (NYCA) (LI ≥ SENY ≥ EAST ≥ NYCA).

[6] See the Appendix (Section 8.1) for a more detailed description of differences in power regulation price volatility across ISO/RTO markets.

[7] The CAISO certified its first solar facility to provide spinning reserve in June 2019, but the amount of reserves solar has provided has been extremely small (CAISO, 2020a). CAISO is also developing participation models that would allow hybrid (2021 implementation) and standalone (planned stakeholder process) VRE to participate more fully in AS markets (CAISO, 2020b). SPP appears to allow VRE to provide downward power regulation reserves (Southwest Power Pool, 2020), though it is not clear how frequently it is doing so. ERCOT reportedly allows wind generators to quality for AS provision, but only a limited number have and wind participation in power regulation markets is minimal (Chernyakhovskiy et al., 2019).

[8] Under the CAISO's proposed participation model for hybrid resources, hybrid VRE would be eligible to provide AS in 2021 (CAISO, 2020b).

[9] Power regulation energy refers to the actual energy or curtailed energy (MWh) provided by a resource with a power regulation reserve award. Contingency dispatch energy refers to the energy provided by a resource with a spinning or non-spinning reserve award in response to a contingency.

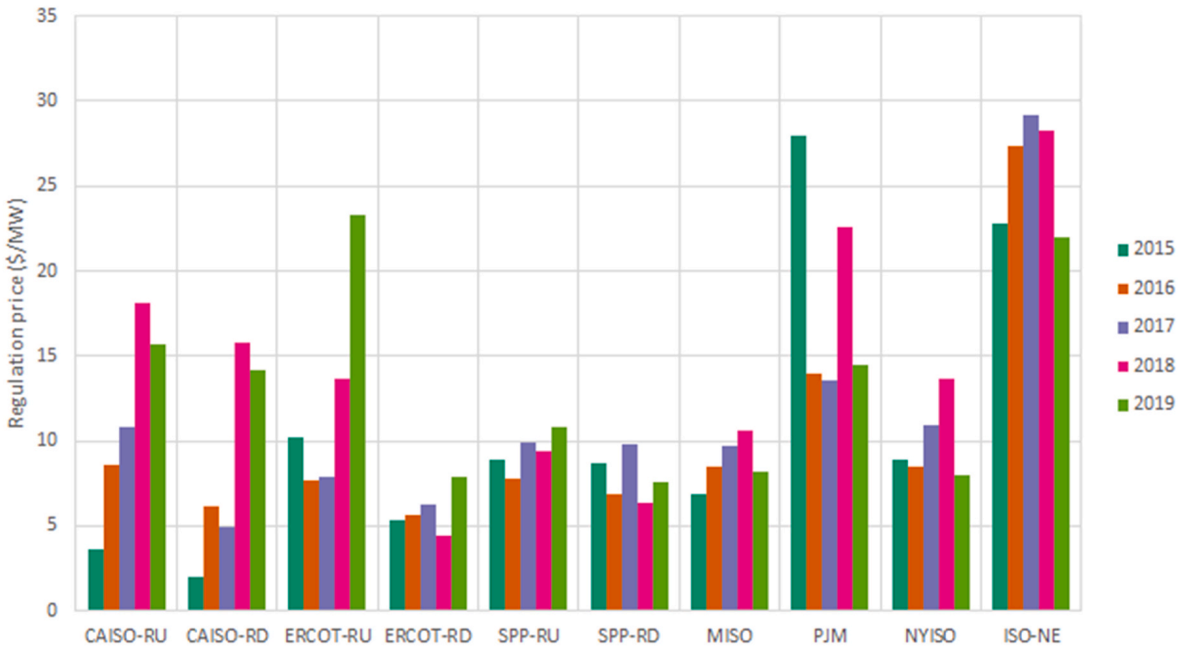

Fig. 1. Average zonal power regulation prices used in this analysis by ISO/RTO, 2015–2019. Notes: RU refers to power regulation up, and RD refers to power regulation down. The figure shows simple averages. Consistent with our analysis, the figure shows real-time power regulation market prices for all ISOs/RTOs except for ERCOT, for which the figure shows day-ahead prices. All years here and in the report are in Greenwich Mean Time (GMT).
Source: Prices are from Velocity Suite. See Section 8.2 for AS price zones.

52 MWh × $25/MWh]/12).[10]

Hybrid VRE participation in real-time AS markets is fundamentally different and more complex than for standalone VRE. In principle, a hybrid facility could provide reserves up to some fraction of its 5-min forecast plus the maximum net charge/discharge rate of the storage component, but will also be limited by the energy in the storage component and its interconnection limits. For instance, a hybrid facility with a 20-MW 5-min forecast and 5 MW of battery capacity could provide up to 25 MW of reserves, but in practice it will be limited by forecast accuracy, the duration and state of charge of the battery, and its interconnection limit.

Interconnection limits, determined as part of the generator interconnection progress, set the maximum amount of power that a facility can inject into the grid. Interconnection limits for standalone VRE may be sized to the nameplate capacity of the facility, in which case they may not have a significant impact on power and reserve provision. Interconnection limits for hybrid VRE may be sized to the nameplate capacity of the generator, the combined nameplate capacity of the generator and storage facility, or something in between. If sized below the combined generator and storage capacity, interconnection limits may limit the facility's ability to fully dispatch and provide reserves.

2.2.2. *Economic principles*

AS marginal prices typically include two components: capacity bids and opportunity costs. In addition, most ISOs/RTOs have separate clearing prices for mileage,[11] compensating power regulation providers for their performance in response to automatic generation control (AGC) signals. Opportunity cost is the largest component of these three elements of AS pricing.

Standalone VRE owners maximize profits from energy and AS markets by choosing the amount of capacity that will participate in each market. Participating in AS markets for upward reserves (UR) requires holding capacity in reserve through pre-curtailment and foregoing participation in the energy market ($dQ^{UR} = -dQ^{E}$). The change in profits for resource owners for providing an additional unit of upward reserves ($d\pi/dQ^{UR}$) is

$$\frac{d\pi}{dQ^{UR}} = \left(P^{UR} - C^{UR}\right) - \left(P^{E} - C^{E}\right) \quad (1)$$

where P^{UR} is a market price for upward reserves, C^{UR} is the unit cost of providing upward reserves, P^{E} is an energy market price (LMP), and C^{E} is the unit cost of providing energy.

To provide upward AS, standalone VRE resources have near-zero variable cost ($C^{E} + C^{UR} \approx 0$), which means that, putting aside renewable energy credits (RECs), production tax credits, and other incentives, resource owners increase unit profits ($d\pi/dQ > 0$) when $P^{UR} > P^{E}$. In other words, VRE owners' opportunity cost of providing upward reserves rather than energy will be close to LMP (P^{E}). For instance, if LMP is $20/MWh and the upward reserve price is $25/MW over an interval, a solar PV facility would choose to provide reserves rather than energy.

Over time, and as we assume in this analysis, generators could also incorporate expected earnings from providing upward reserve energy — for instance, power regulation energy or contingency dispatch — in this decision, which ISOs/RTOs compensate at LMP. If the average upward reserve energy is equal to a fraction α^{UR} of Q^{UR}, the change in profits from providing upward reserve ($d\pi/dQ^{UR}$) will be

$$\frac{d\pi}{dQ^{UR}} \cong P^{UR} + \left(\alpha^{UR} - 1\right)P^{E} \quad (2)$$

Where P^{UR} is a market price for upward reserves, α^{UR} is the average upward reserve energy as a fraction of upward reserves Q^{UR}, and P^{E} is an energy market price (LMP).

For instance, if a solar PV facility providing upward power regulation

[10] Hourly equivalent refers to the energy that the unit would have generated or the amount of reserves that would have been provided if the average power output during a 5-min interval was sustained for 1 h. In this case, 50 MWh hourly equivalent would be 4.2 MWh (50 MW average output sustained for 0.08 h) of metered energy over the 5-min interval. Total settlement is divided by 12 to convert to the hourly equivalent settlement to a 5-min settlement. We use hourly equivalents throughout this paper.

[11] PJM incorporates mileage into its power regulation market clearing prices.

reserves expects to be dispatched to provide energy equivalent to 25% of its power regulation award on average ($\alpha^{UR} = 0.25$) and LMP (P^E) is \$20/MWh, it would choose to provide upward reserves ($d\pi/dQ > 0$) as long as the reserve price (P^{UR}) is greater than \$15/MW. At this point, the generator will be indifferent to providing energy ($P^E \times Q^E = \$20$) or reserves ($P^{UR} \times Q^{UR} + \alpha^{UR} \times P^E = \$15 + \$5 = \$20$) in that interval.

Downward power regulation reserve prices are based on the incremental cost of keeping generators above their desired operating points. Participation in downward reserve markets thus requires providing additional energy ($dQ^{DR} = dQ^E$). The change in profits for resource owners for providing an additional unit of downward reserves ($d\pi/dQ^{DR}$) is

$$\frac{d\pi}{dQ^{DR}} = \left(P^{DR} - C^{UR}\right) + \left(P^E - C^E\right) \tag{3}$$

where P^{DR} is a market price for downward reserves, C^{DR} is the unit cost of providing downward reserves, P^E is an energy market price (LMP), and C^E is the unit cost of providing energy.

Standalone VRE resources' near-zero marginal cost thus means that their opportunity cost of providing downward reserves will be close to zero ($dQ^{DR}/dQ^E = 0$) because their desired operating point will almost always be their actual output. The only opportunity cost of VRE providing downward reserve will be lost revenue from providing downward reserve energy through curtailment. If downward upward reserve energy is equal to an average fraction α^{DR} of Q^{DR}, the change in profits from providing downward reserve ($d\pi/dQ^{DR}$) will be

$$\frac{d\pi}{dQ^{DR}} \cong P^{DR} - \alpha^{DR} P^E \tag{4}$$

Where P^{DR} is a market price for downward reserves, α^{DR} is the average downward reserve energy as a fraction of downward reserves Q^{DR}, and P^E is an energy market price (LMP).

For instance, if LMP (P^E) is \$20/MWh and expected downward power regulation energy is 25% of the reserve award ($\alpha^{DR} = 0.25$), a VRE facility would be willing to provide downward reserves as long as the reserve price (P^{DR}) is greater than \$5/MW in that interval. At this point, the VRE generator will be indifferent to providing additional energy ($P^E \times dQ^E = \$0$) or downward reserves ($P^{DR} \times Q^{DR} - \alpha^{DR} \times P^E = \$5 - \$5 = \$0$).

In cases where power regulation is a bidirectional product and expectations for upward and downward power regulation energy are symmetric ($\alpha^{UR} = \alpha^{DR}$), the breakeven condition for power regulation reserve provision is that the power regulation price must exceed the energy price, because the power regulation energy benefits and costs will offset ($\alpha^{UR}P^E = -\alpha^{DR}P^E$). For instance, consider a case in which a VRE facility is providing 10 MW of bidirectional power regulation reserves over some real-time interval, faces a power regulation price of \$25/MW and an energy price of \$20/MWh, and expects to provide 25% of its power regulation award in upward and downward power regulation energy. The \$42 (= [10 MW × 0.25 MWh/MW × \$20/MWh]/12) that the facility will earn from upward power regulation energy is offset by the \$42 (= [10 MW × −0.25 MWh/MW × \$20/MWh]/12) that it will effectively pay from downward power regulation energy and its expected revenues will be \$21 (= [\$25/MW × 10 MW + \$500 - \$500]/12). If the power regulation price exceeds the energy price, the unit will prefer to provide reserves.

The asymmetry in opportunity costs for VRE provision of upward and downward reserves suggests that VRE will more frequently provide downward power regulation reserves in markets where separate upward and downward power regulation products exist. However, the unit value of providing upward reserves would likely be higher than for downward reserves because VRE will only provide upward reserves when the reserve price is close to or exceeds the energy price.

The frequency with and the conditions under which upward power regulation (CAISO, ERCOT, SPP) or bidirectional power regulation (ISO-NE, MISO, NYISO, PJM) prices exceed energy prices vary across markets, from a low of 368 h in MISO to a high of 2205 h in ISO-NE in our energy and AS price zones in 2018, though it was less than 1500 h (17% of hours) in all markets except for ISO-NE. In most markets, positive differences between power regulation and energy prices tended to be clustered in lower energy price hours, whereas for PJM and ISO-NE positive spreads were more evenly distributed across energy prices. Fig. 2 illustrates this difference in price dynamics, using CAISO and PJM as illustrative examples.

For hybrid VRE, the economics of energy versus reserve provision is more complex because its opportunity cost extends both across energy and reserve markets and over time and because of the interactions between the generator and the storage device, which occur either due to interconnection limits or if the battery can only charge from the generator. If the interconnection limit does not bind and battery charging/discharging is not limited by the generator, generation, and storage will operate independently. In this case, the economic principles described above for the VRE generator will still hold.

The battery in a hybrid VRE will tend to maintain a state of charge that allows it to provide maximum amounts of upward and downward reserves unless energy price differences are high enough or reserve prices are low enough to perturb this equilibrium and cause the battery to charge/discharge for energy price arbitrage or choose to provide neither energy nor reserves.

For instance, a 10 MW/20 MWh battery may charge to just over 10 MWh (incorporating efficiency losses) to provide 10 MW of upward power regulation and 10 MW of downward power regulation. If energy prices are high, the battery may charge to 20 MWh during a lower priced hour and then discharge to take advantage of these higher prices, but during the intervals when it is fully charged, it cannot provide downward reserves, and during the interval when it is fully discharged it cannot provide upward power regulation. The net income earned from energy arbitrage must be high enough to offset the opportunity cost of not providing reserves. Tradeoffs like this make battery behavior complex, particularly in real-world applications where resource owners do not have perfect foresight.

Power regulation product design also affects the dispatch, and thus the economics, of VRE hybrids. In markets with bidirectional power regulation products, power regulation prices reflect the incremental cost of providing upward and downward power regulation reserves simultaneously. However, in markets with separate upward and downward power regulation products, upward and downward power regulation prices tend to be weakly correlated.[12] This suggests that, in bidirectional power regulation markets, resources with power regulation awards will need to provide power regulation reserves in both directions even though the value (market price) in one direction may be low or though the resource may not physically be able to provide power regulation reserves in both directions but can provide high value reserves in one direction.

In practice, market decision-making for both standalone and hybrid VRE resources will be more complex than the above discussion suggests, because of the influence of renewable incentives, emissions pricing, contractual obligations, resource and performance uncertainty, higher levels of curtailment, and other factors that may shape real-time bidding behavior. For instance, in their bid strategies, VRE owners would need to factor in the incremental cost of lost RECs or production tax credit (PTC) revenues from providing reserves rather than energy. We do not consider these factors in the analysis.

[12] For instance, based on the AS prices used in this analysis, CAISO day-ahead upward and downward power regulation prices had a correlation coefficient of 0.19 and a real-time correlation coefficient of 0.02 in 2018; in ERCOT the correlation coefficient for day-ahead upward and downward power regulation prices was 0.22; in SPP, the day-ahead correlation coefficient was 0.05 and the real-time correlation coefficient was 0.04.

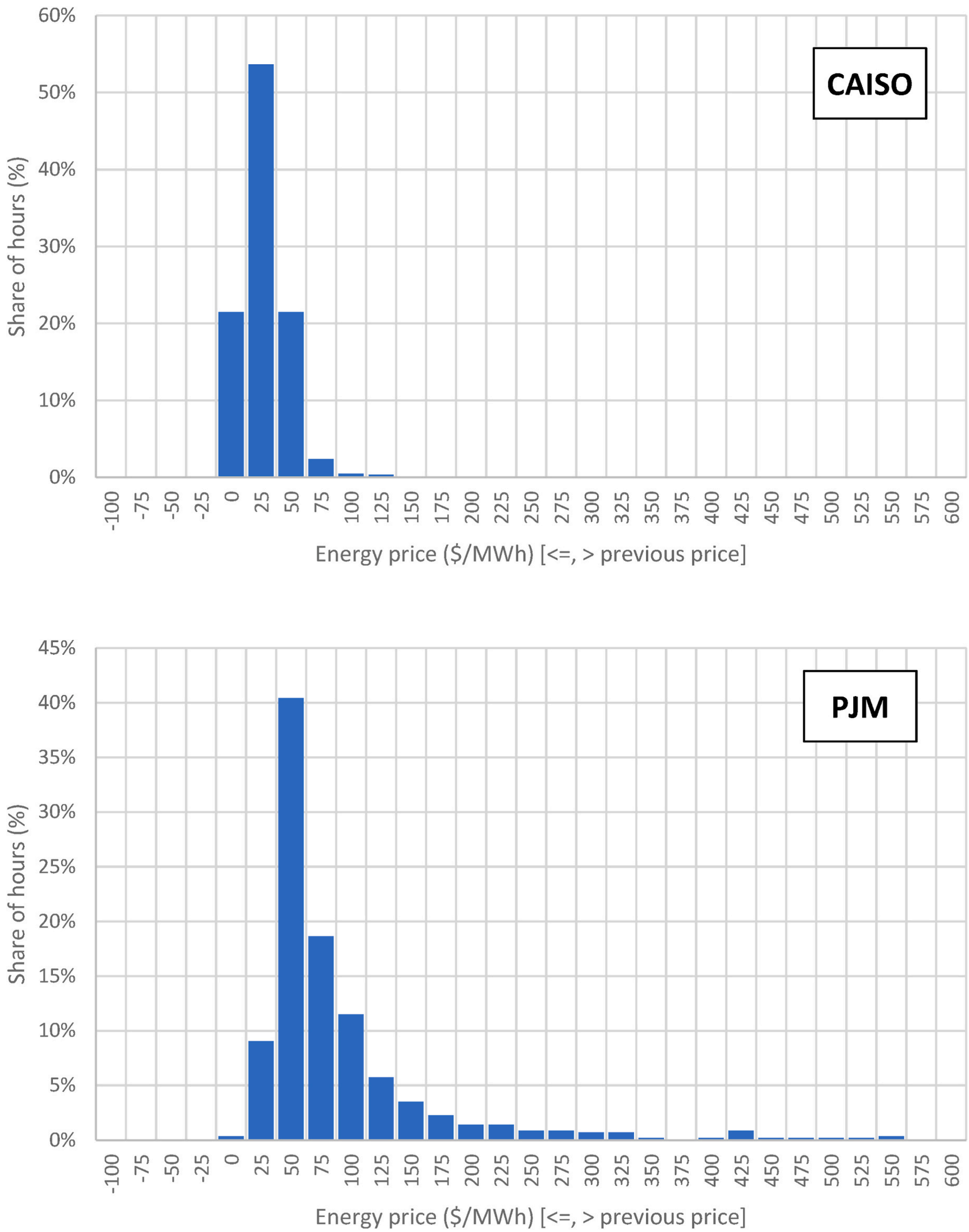

Fig. 2. Share of Hours in Which Power Regulation Prices Exceeded Energy Prices in CAISO and PJM at Different Energy Price Levels, 2018. Note: Energy prices in the above figures are the maximum of each energy price bin and the previous price is the minimum of each bin. For instance, \$50/MWh is the bin in which \$25/MWh $<$ energy price $\leq$ \$50/MWh.

3. Methods

This section describes analysis metrics and our modeling framework and assumptions. Section 7.2 provides additional detail on methods and describes data sources.

3.1. Metrics

The analysis examines the value of VRE AS market participation from a VRE resource owner's and an electricity system perspective in each of the seven ISO/RTO markets. In both cases, we compare a scenario in which the VRE resource does not participate in AS markets to one in which it does.

For resource owners, we measure value to the resource owner in terms of incremental unit revenues (Δr, $/MWh$_{PC}$) from participating in AS markets, where

$$\Delta r = \frac{EN_1 + AS_1 - EN_0}{G_{PC}}$$

And where.

- EN is the VRE facility's annual energy market revenues in $/year
- AS is the VRE facility's annual AS market revenues in $/year
- G_{PC} is the pre-curtailment (PC) amount of annual generation from the VRE facility in MWh$_{PC}$/year
- Subscript 1 is the scenario in which the facility provides both energy and AS (energy + AS)
- Subscript 0 is the scenario in which the facility only provides energy (energy only)

The numerator in this equation captures the change in total revenues for the standalone or hybrid VRE facility due to AS market participation. For the denominator, we use pre-curtailment generation to provide a consistent basis for comparing unit revenues in the energy + AS and energy-only scenarios because the amount of annual generation in the two scenarios will differ due to curtailment ($G_0 > G_1$). Incremental unit revenues do not include degradation costs for hybrid VRE.

For the system perspective, we measure value in terms of average annual unit value (v, $/MW), where

$$v = \frac{AS_1}{RS_1}$$

And where.

- RS_1 is the VRE facility's annual provision of AS in MW/yr

This annual unit value can be compared against average AS market prices to assess whether VRE can provide reserves during high-priced hours. For instance, a solar facility that provides upward power regulation reserves mainly during system-constrained periods with high power regulation prices will tend to have a high unit value relative to average upward power regulation prices.

As an additional metric for system value, we also report the amount of average reserves (AR, MW) provided by the VRE facility over the year, where

$$AR = \frac{RS_1}{H}$$

And where.

- H is the number of hours in the year (8760 or 8784)

3.2. Modeling framework and assumptions

To estimate Δr, v, and AR, we use a linear optimization model that maximizes wholesale market revenues against zonal energy and AS market prices for standalone and hybrid VRE resources in each ISO/RTO market, with consistent assumptions across markets to allow for comparability.

The analysis considers four resource types:

1) a 20-MW standalone solar PV plant
2) a 20-MW standalone onshore wind plant
3) a 20-MW hybrid solar PV plant paired with 10 MW/40 MWh of battery storage
4) a 20-MW hybrid onshore wind plant paired with 10 MW/40 MWh of battery storage

The hybrid results should not be compared against the standalone results to assess whether storage would be cost-effective for VRE owners. There are other potential benefits to hybridization, such as interconnection cost savings and capacity value, that are not considered in this analysis.

In a base case, we examine the participation of these four resources in ISO/RTO power regulation markets, as power regulation tends to be the highest-value AS product. In sensitivity analyses, we consider participation in both power regulation and spinning reserve markets and only in spinning reserve markets.[13] The model uses hourly average zonal energy, power regulation, and spinning reserve prices from 2015 through 2019, with zones selected based on a centroid search algorithm to reflect an average plant (see Section 8.2). For the six ISOs/RTOs that have real-time AS markets, the model uses real-time energy and AS prices because real-time prices set arbitrage conditions for resource owners. The model uses day-ahead prices for ERCOT, which did not have a real-time AS market during 2015–2019.

The model uses deterministic solar and wind profiles (see Section 8.2 for data sources and methods). For standalone plants, reserve market participation is capped at 20% of the hourly profile, with minimum participation of 1 MW. The 20% cap is intended to reflect a reasonably conservative level of participation, accounting for VRE forecast error, though ultimately, participation limits should be driven by historical data and desired levels of confidence. The 1 MW floor captures differences among ISO/RTO eligibility criteria. For instance, the minimum size for participation in PJM's power regulation markets is 0.1 MW (PJM, 2021), ISO-NE's minimum size ranges from 0.1 MW (storage) to 5 MW (generation) (Independent System Operator – New England, 2021), and SPP's tariff does not stipulate a minimum size (Southwest Power Pool, 2020). The cap has a significant impact on the results, as the value of providing AS is approximately proportional to the cap, whereas the floor does not significantly impact the results.

For hybrid plants, the model allows the generator and battery to operate independently but only allows the battery to provide reserves, as battery reserve provision will significantly exceed that for the solar or wind generator.[14] In the base case, the point of interconnection (POI) capacity limit is capped at the wind or solar generator nameplate capacity (20 MW), though we consider a sensitivity in which the POI limit is increased to the nameplate capacity of the generator plus the

[13] We do not consider participation in non-spinning reserve markets. In these markets, generators do not have energy market opportunity costs and thus market prices tend to be significantly lower than for spinning reserves (Denholm et al., 2019).

[14] In principle, both the battery and the generator could provide reserves, with the latter providing them through curtailment. Given that the reserves provided by the battery are likely to be much larger than those provided by the generator, we only include the former in this analysis.

maximum discharge capacity of the battery (30 MW). The model conservatively caps reserve provision by the battery at its maximum charge/discharge capacity.[15] It uses a degradation penalty of \$5/MWh for energy dispatched from the battery and \$25/MWh for energy, including reserve energy, provided by the battery.[16]

For both the standalone and hybrid plants, we assume that plant owners incorporate the revenues and costs of power regulation energy and contingency dispatch in their market bids, which is captured in the model's objective function. For power regulation, we assume that the plant provides upward or downward power regulation energy equivalent to 25% of its power regulation award.[17] For spinning reserves, we assume that the plant provides contingency dispatch energy equivalent to 2% of its spinning reserve award. Two percent is a conservative estimate that assumes a maximum of roughly 175 h of contingency events per year.[18]

For simplicity, the model assumes perfect foresight of future market prices, which affects both standalone and hybrid VRE dispatch. For standalone VRE, resource owners do not know the market prices at which they will provide power regulation energy in advance, which means that to factor power regulation energy into their bids resource owners would need to rely on historical prices. For hybrid VRE, resource owners must manage battery state of charge faced with uncertainty around future prices, which means that batteries may not be able to provide energy and reserves as efficiently as they would be able to with perfect foresight. In both cases, incremental unit revenues (Δr) will tend to be lower without perfect foresight than with it, though the effect will be larger for hybrid than standalone VRE.

The model assumes that AS market prices do not change as additional VRE resources participate in these markets. This price taker assumption is valid for early market entrants but would be less reasonable with higher levels of VRE participation in AS markets. We discuss this assumption in further detail in Section 5.2.

The model does not include power regulation mileage revenues, as these are difficult to model, and total mileage payments to resources tend to be small. It also does not consider limits on dispatch imposed by external incentives, such as RECs or the federal PTC, contract terms and conditions, or other sources of uncertainty for resource owners. In general, incentive and contractual constraints will tend to reduce incremental unit revenues by providing a disincentive for curtailment (standalone) and constraining dispatch (hybrids), though the effects will be unit and market-specific.

4. Results

This paper seeks to answer three main research questions: Firstly, what participation models and economic principles would underpin VRE participation in U.S. AS markets? Secondly, what is the value of VRE participation in AS markets to resource owners and the electricity system, and how do sensitivities affect the results? Thirdly, how do AS market participation barriers, changes in AS market volumes and pricing, and changes in market design and AS products affect the results? This section aims to provide a clear structure for the main insights found regarding the value of VRE participation in AS markets to both resource owners and system operators.

4.1. Value to standalone VRE owners

Figs. 3 and 4 show the base case results for standalone VRE owners by year and ISO/RTO. The tables below each figure show simple average incremental unit revenues (Δr) across 2015–2019 and the percentage change in 2015–2019 average revenues from providing power regulation reserves and energy relative to only providing energy.[19]

As the figures show, incremental value to standalone VRE owners varies significantly among ISOs/RTOs, across years, and between wind and solar resources. Differences among ISOs/RTOs stem from different power regulation products, price levels, and the relationship between energy and power regulation prices. The incremental value for resource owners is generally higher in ISOs/RTOs with separate upward and downward power regulation products (CAISO, ERCOT, SPP) than in ISOs/RTOs with bidirectional power regulation (MISO, PJM, NYISO, ISO-NE). As described in Section 2.2.2, the main reason for this result is that, with separate products, VRE can provide downward power regulation in most hours, whereas with bidirectional power regulation products VRE will only provide downward power regulation in a limited number of hours in which power regulation prices are higher than energy prices.

Higher average annual power regulation prices, for instance, ERCOT in 2019 or PJM in 2015 and 2018, tend to translate into higher estimated incremental value for standalone VRE owners in some years but are generally outweighed by the effects of different market designs. SPP, for instance, had lower average power regulation prices than PJM during 2015–2019 but has higher incremental value because it has separate upward and downward power regulation products.

In addition to power regulation price levels, differences in results across years are also the result of changes in power regulation procurement and the relationship between energy and power regulation prices. For instance, CAISO increased its power regulation procurement in 2016, leading to 1.4-fold and 2.1-fold increases in upward and downward power regulation prices, respectively, and an increase in incremental value. Increases in incremental value for both solar and wind in CAISO in 2018 were driven by higher increases in power regulation prices relative to energy prices and an increase in the number of hours where power regulation prices exceeded energy prices. As mentioned in Section 2.1, some of the changing power regulation price dynamics in CAISO over this period were driven by increases in solar generation (Mills et al., 2021).

Differences between wind and solar are the result of different resource profiles relative to power regulation prices and differences in capacity factors. Wind's average incremental value and percentage change in revenues are higher than solar's in all markets except for CAISO and ERCOT. In ERCOT, solar's incremental value is higher but wind's percentage change in revenues is higher, highlighting the impact of differences in capacity factors between solar and wind. Wind has a higher capacity factor than solar, meaning that its higher incremental revenues are spread over a larger denominator and may be lower than for solar, on a \$/MWh basis, as is the case in the ERCOT results.

The results for PJM are within the range but on the lower side of those in Rebello et al. (2020), who estimate a 1–6% increase in revenues for a wind plant providing power regulation in PJM in 2017.

[15] In principle, a battery that is charging/discharging at 10 MW could provide up to 20 MW of upward/downward power regulation. More conservatively, we limit reserve provision to maximum charge/discharge capacity, or in this example 10 MW.

[16] These estimates, based on He et al. (2018), reflect the long-run opportunity cost of operating the battery more in the nearer versus the longer term. Above a relatively low degradation penalty level, the choice of degradation penalty does not significantly affect the results.

[17] This assumption is consistent with the default parameter in Sandia National Laboratory's (SNL's) QUEST tool, https://github.com/snl-quest/snl-quest.

[18] This assumes that a resource providing 1 MW of spinning reserves in each hour of the year would be called upon to provide 175 MWh of energy per year, or 175 total event hours if fully loaded.

[19] We calculate percentage change in average revenues as the percentage difference between average unit revenues over 2015–2019 from providing energy and power regulation reserves and average unit revenues over 2015–2019 from providing energy only. Because unit revenues in both cases are normalized by pre-curtailed MWh (MWh_{PC}), the denominators are the same and the percentage change in unit revenues is equal to the percentage change in total revenues.

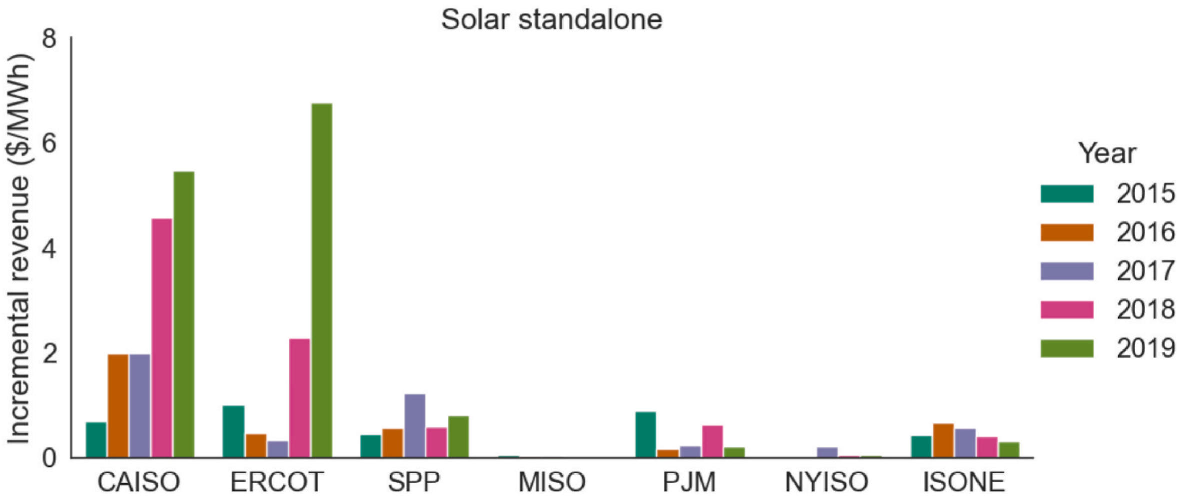

Fig. 3. Incremental unit revenue ($/MWh$_{PC}$) to standalone solar owner (Figure), 2015–2019 average incremental revenue (table), and percentage change in 2015–2019 average revenue (table).

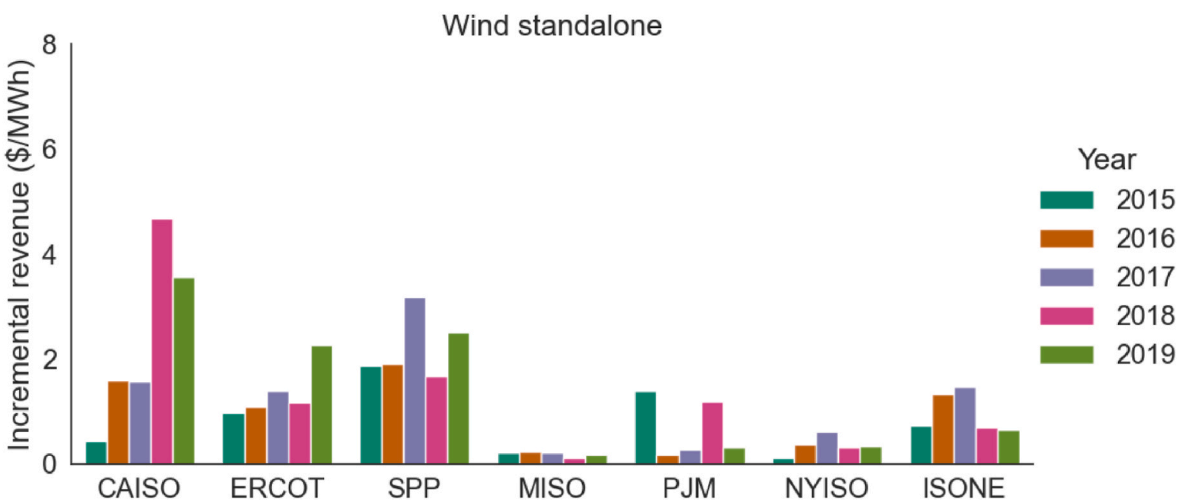

Fig. 4. Incremental revenue ($/MWh$_{PC}$) to standalone wind owner (Figure), 2015–2019 average incremental revenue (table), and percentage change in 2015–2019 average revenue (table).

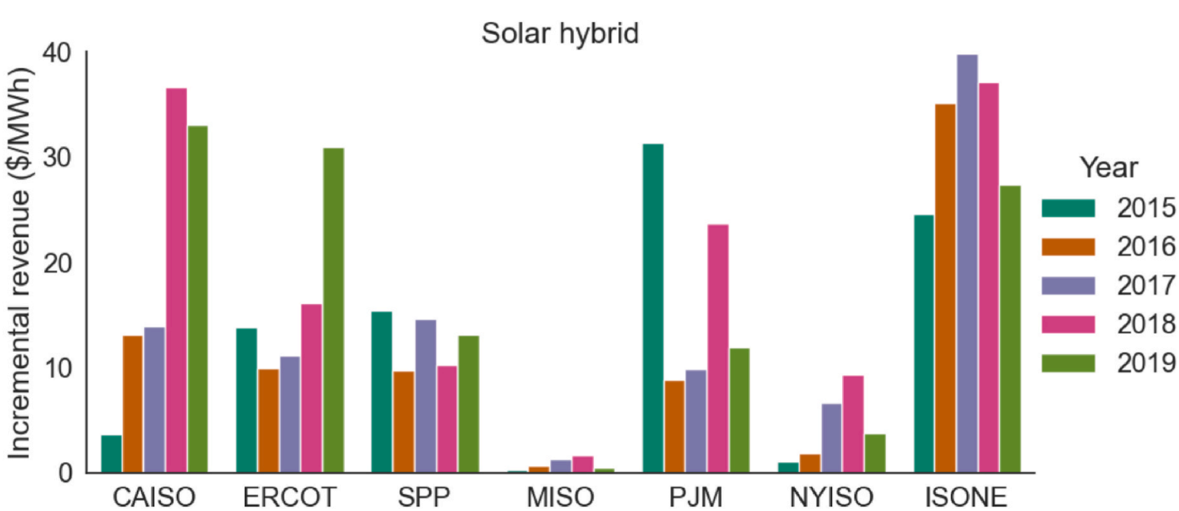

Fig. 5. Incremental revenue ($/MWh$_{PC}$) to hybrid solar owner (Figure), 2015–2019 average incremental revenue (table), and percentage change in 2015–2019 average revenue (table).

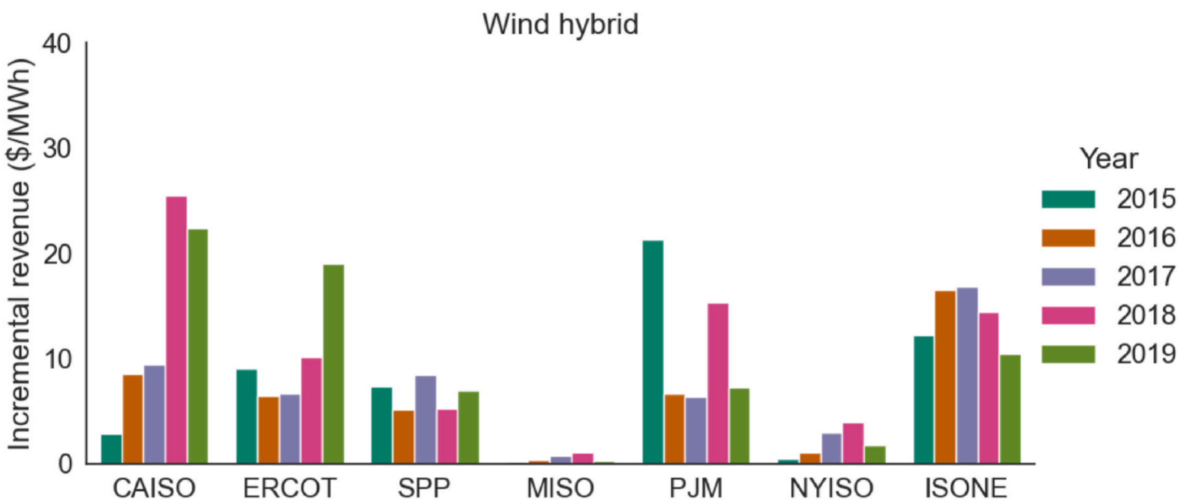

Fig. 6. Incremental revenue ($/MWh$_{PC}$) to hybrid wind owner (Figure), 2015–2019 average incremental revenue (table), and percentage change in 2015–2019 average revenue (table).

4.2. Value to hybrid VRE owners

As Figs. 5 and 6 show, incremental value for hybrid VRE owners is significantly higher than for standalone VRE owners in most markets. Given the discussion in Section 2.2.2, this result is expected: batteries will tend to provide reserves unless energy price differences are high or reserve prices are low, whereas standalone VRE will tend to provide energy unless reserve prices are high relative to energy prices.

Differences in value among ISOs/RTOs and years are mainly driven by differences in market design and power regulation price levels. For instance, MISO and SPP had similar real-time energy and power regulation price levels and price variance during 2015–2019,[20] but hybrid batteries provide significantly more incremental revenue in SPP than in MISO because SPP has separate upward and downward power regulation products, which allows batteries to provide power regulation more efficiently (see Section 2.2.2). For PJM and ISO-NE, higher power regulation prices (Fig. 1) explain why incremental revenues in these markets are higher than in MISO and NYISO.

As with standalone VRE, differences between the solar and wind results are driven mainly by differences in resource profiles and capacity factors but are, to a much lesser extent, influenced by the POI capacity constraints (see Section 4.4).

4.3. Value to the electricity system

Table 2 and Table 3 show modeled results for both the power regulation provision (*AR*) and power regulation value (*v*) metrics, using 2018 ISO/RTO market prices.[21] In Table 2, power regulation provision is shown both as average MW and as percent of the generator or battery's nameplate capacity of (20 MW for standalones, 10 MW for hybrids). In comparing across ISOs/RTOs, it is important to bear in mind that in markets with bidirectional power regulation the VRE facility will be providing power regulation in both directions, which means that the "Total" power regulation provision for markets with separate power

Table 2
Simulated VRE power regulation provision (*AR*).

		Power regulation provision (AR, average MW), % capacity in parentheses			
		Standalone		Hybrid	
		Solar	Wind	Solar	Wind
CAISO	RD	0.95 (5%)	0.91 (5%)	4.37 (44%)	4.23 (42%)
	RU	0.42 (2%)	0.47 (2%)	3.92 (39%)	3.54 (35%)
	Total	1.37 (7%)	1.38 (7%)	8.29 (83%)	7.78 (78%)
ERCOT	RD	0.18 (1%)	0.82 (4%)	1.49 (15%)	1.45 (14%)
	RU	0.24 (1%)	0.54 (3%)	3.09 (31%)	3.10 (31%)
	Total	0.42 (2%)	1.36 (7%)	4.58 (46%)	4.55 (45%)
SPP	RD	0.28 (1%)	1.32 (7%)	2.73 (27%)	2.42 (24%)
	RU	0.15 (1%)	0.70 (3%)	2.43 (24%)	2.20 (22%)
	Total	0.43 (2%)	2.02 (10%)	5.16 (52%)	4.63 (46%)
MISO		0.03 (0%)	0.28 (1%)	1.22 (12%)	1.33 (13%)
PJM		0.11 (1%)	0.27 (1%)	6.15 (62%)	6.00 (60%)
NYISO		0.04 (0%)	0.38 (2%)	3.79 (38%)	3.05 (30%)
ISO-NE		0.16 (1%)	0.51 (3%)	10.19 (102%)	8.26 (83%)

Notes: RD refers to downward power regulation; RU refers to upward power regulation; total power regulation is the sum of upward and downward power regulation, which can exceed the nameplate capacity of the battery or 100% in percentage terms.

Table 3
Simulated VRE power regulation value (*v*), Using 2018 market prices.

		Power regulation value (*v*) and ISO average power regulation price in 2018 ($/MW)				
		Standalone		Hybrid		ISO AVG
		Solar	Wind	Solar	Wind	
CAISO	RD	$26	$31	$31	$32	$12
	RU	$37	$62	$38	$40	$14
	Total	$29	$42	$34	$36	
ERCOT	RD	$8	$11	$14	$15	$4
	RU	$78	$16	$32	$32	$14
	Total	$48	$13	$26	$27	
SPP	RD	$12	$13	$15	$16	$9
	RU	$34	$14	$22	$23	$6
	Total	$19	$13	$18	$19	
MISO		$7	$6	$12	$12	$11
PJM		$67	$64	$26	$27	$23
NYISO		$10	$11	$15	$15	$14
ISO-NE		$34	$32	$21	$21	$28

Notes: RD refers to downward power regulation; RU refers to upward power regulation.

[20] For instance, based on the energy and AS prices used in this study, MISO's average real-time energy prices were $26/MWh ($C_V$ = 0.7) and its power regulation prices were $11/MW-h ($C_V$ = 1.0), whereas SPP's average real-time energy prices were $24/MWh ($C_V$ = 1.0) and its upward and downward power regulation prices were $9/MW-h ($C_V$ = 1.9) and $6/MW-h ($C_V$ = 1.2), respectively.

[21] The choice of year here is arbitrary. The key findings from this analysis are general enough where the choice of year will not have a significant impact on the results.

regulation products is comparable with twice the amount of power regulation in markets with bidirectional power regulation. Table 3 also shows simple average ISO/RTO power regulation prices in 2018 (ISO AVG), as a point of comparison for the power regulation value metric.

The results in Tables 2 and 3 can be distilled into four key points. First, power regulation provision is generally higher in the markets with separate upward and downward power regulation products than in those with bidirectional power regulation, even accounting for the fact that resources providing bidirectional power regulation are providing it in both directions (hybrid VRE in ISO-NE and PJM are exceptions). For instance, a standalone wind facility in SPP provides 1.3 MW (7% of nameplate) of downward and 0.7 MW (3%) of upward power regulation, whereas a standalone wind facility in MISO provides only 0.3 MW (1%) of bidirectional power regulation. In particular, having separate upward and downward power regulation products allows VRE to provide downward power regulation in situations where, with bidirectional power regulation, power regulation prices would have needed to exceed energy prices to have made it cost-effective for VRE to provide power regulation reserves (see Section 2.2.2).

Second, standalone wind almost always provides more average reserves than standalone solar (CAISO RD is the only exception), but hybrid solar provides slightly more reserves than hybrid wind (ERCOT RU and MISO are the exceptions). Differences between solar and wind reserve provision are driven by resource profiles and the ISO/RTO resource mix, reflected in market prices. The relative unit value (v) of solar and wind vary across markets without a clear pattern, though the value of solar and wind are relatively close for hybrid VRE and both standalone and hybrid VRE in bidirectional markets.

Third, the value of hybrids is often, though not always, higher than standalone VRE (CAISO wind RU, ERCOT solar RU, SPP solar RU, PJM, and ISO-NE are exceptions). Cases, where standalone VRE has a higher value may reflect instances where they provide power regulation reserves in a small number of high-priced (high value) hours, whereas hybrids provide reserves in a larger number of hours and thus have lower average value, illustrating that standalone VRE can provide high-value reserves.

Fourth, the value for both standalones and hybrids is higher than ISO/RTO average power regulation prices in almost all cases (MISO and NYISO standalones are the exceptions), which implies that VRE tends to provide power regulation reserves during periods when power regulation prices are higher than average. This result suggests that enabling power regulation market participation by these resources would help to put downward pressure on average power regulation prices.

4.4. Sensitivities

The analysis considers four sensitivities:

- **Max POI**, in which we increase the POI limit from 20 MW to 30 MW for the hybrid VRE resources.
- **Energy + reg + spin**, in which we allow standalones and hybrids to provide spinning reserve in addition to energy and power regulation.
- **Energy + spin**, in which we only allow standalone VRE and hybrids to provide energy and spinning reserve.
- **High VRE penetration**, in which we explore how incremental revenues (Δr) from power regulation market participation might change with higher VRE penetrations.

We use 2018 ISO/RTO market prices for the first three sensitivities. For the high VRE penetration sensitivity, we use 2030 energy and power regulation price projections for two scenarios in Seel et al. (2018): (1) the Low VRE scenario, in which wind and solar generation is capped at 2016 levels, and (2) the "balanced wind/solar, consistent capacity balancing" case from the High VRE scenario. The balanced wind and solar case has 20% solar and 20% wind in each of the four markets (CAISO, ERCOT, NYISO, SPP) in 2030.

Table 4
Incremental revenue ($/MWh$_{PC}$) to VRE owners for base case (energy + reg), max POI, energy + reg + spin, and energy + spin Sensitivities, 2018 ISO/RTO prices.

	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Standalone solar							
Base case (energy + reg)	$4.6	$2.3	$0.6	$0.0	$0.6	$0.1	$0.4
Energy + reg + spin	$4.9	$3.0	$0.6	$0.0	$0.6	$0.1	$0.4
Energy + spin	$0.3	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0
Standalone wind							
Base case (energy + reg)	$4.7	$1.2	$1.7	$0.1	$1.2	$0.3	$0.7
Energy + reg + spin	$5.2	$1.5	$1.7	$0.1	$1.2	$0.3	$0.7
Energy + spin	$0.5	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0
Hybrid solar							
Base case (energy + reg)	$36.7	$16.1	$10.2	$1.7	$23.6	$9.4	$37.1
Max POI	$37.9	$18.2	$11.5	$2.3	$26.7	$10.1	$40.7
Energy + reg + spin	$36.7	$17.8	$10.5	$2.1	$23.5	$9.4	$37.0
Energy + spin	$2.8	$8.3	$0.9	$0.8	$0.8	$0.8	$0.7
Hybrid wind							
Base case (energy + reg)	$25.4	$10.1	$5.3	$1.1	$15.3	$4.0	$14.4
Max POI	$27.3	$11.0	$6.3	$1.4	$17.8	$5.1	$20.0
Energy + reg + spin	$25.4	$10.9	$5.4	$1.3	$15.2	$3.9	$14.4
Energy + spin	$1.9	$5.2	$0.4	$0.5	$0.4	$0.2	$0.3

Table 4 shows the results for the first three sensitivities. It includes base case (energy + reg) incremental values for 2018 as a reference. The results illustrate two main points. First, with exceptions in ISO-NE and PJM, the value of increasing the POI capacity limit is relatively low. This finding implies that assuming the battery is sized to less than 50% of the nameplate capacity of the VRE facility, most of the hybrids' AS value can be captured without needing to increase a wind or solar facility's interconnection capacity limit.

Second, the incremental value of participating in spinning reserve markets, either in addition to power regulation markets (energy + reg + spin) or without participation in power regulation markets (energy + spin), is low. This result is partly due to price cascading, meaning that in CAISO, MISO, and SPP power regulation, prices will always exceed spinning reserve prices (see Table 1) and partly due to low spinning

Table 5
Incremental revenue ($/MWh$_{PC}$) to VRE owners, high VRE and low VRE scenarios in the high VRE penetration sensitivity.

	CAISO	ERCOT	SPP	NYISO
Standalone solar				
High VRE	$1.4	$6.6	$14.8	$2.0
Low VRE	$0.0	$0.1	$0.0	$0.0
Standalone wind				
High VRE	$1.3	$2.7	$6.6	$1.4
Low VRE	$0.0	$0.5	$0.3	$0.0
Hybrid solar				
High VRE	$34.3	$40.8	$64.1	$20.6
Low VRE	$5.4	$25.2	$7.1	$0.9
Hybrid wind				
High VRE	$21.6	$22.3	$35.9	$10.0
Low VRE	$3.2	$12.0	$3.4	$0.6

reserve prices relative to energy and power regulation prices.

Table 5 shows results for the high VRE penetration sensitivity, displaying incremental revenues (Δr) to VRE owners for both the High VRE and Low VRE scenarios in the four markets with 2030 price projections in Seel et al. (2018). We show results for these scenarios separately rather than just the difference between them to highlight that these results are comparable with one another but are not strictly comparable with those in Sections 4.1 and 4.2. The latter are based on historical market prices, whereas the high VRE penetration sensitivity is based on 2030 price projections.

Incremental value to VRE owners increases substantially from the Low to High VRE scenarios, particularly in ERCOT and SPP. Two main factors drive these results. First, projected power regulation prices are significantly higher in the High VRE scenario than in the Low VRE scenario. For instance, in SPP projected downward power regulation prices increase from an average of around $4/MW-h to $27/MW-h. Second the frequency with which projected power regulation prices exceed projected energy prices is also higher in the High VRE scenario than in the Low VRE scenario. For instance, in ERCOT the number of hours where upward power regulation prices exceed energy prices increases from around 100 in the Low VRE scenario to around 1500 in the High VRE scenario.

The results in Table 5 are intended to be illustrative and directional rather than forecasts. Importantly, the High VRE scenario in Seel et al. (2018) does not include significant amounts of energy storage and does not allow VRE to participate in AS markets, both of which would tend to depress the incremental value of AS market participation for VRE resource owners.

5. Key issues

The results are sensitive to market participation barriers (will VRE be able to participate in AS markets?), changes in AS market volumes and pricing (how would higher VRE penetration and VRE and storage participation in AS markets affect the results?), and changes in market design (will new AS products provide additional revenue opportunities for VRE?). This section explores these three issues.

5.1. Market participation barriers

As discussed in Section 2.2, standalone and hybrid VRE resources are not meaningfully participating in ISO/RTO power regulation and spinning reserve markets. For both standalone and hybrid resources, the most important barriers to participation in power regulation and spinning reserve markets are forecast uncertainty, duration requirements, and perceived disincentives created by policy.

All generation resources have some degree of weather dependence, which affects the operating characteristics (ramp rates, maximum and minimum generation levels) that determine their ability (operating limits) to provide reserve capacity over a day. For solar and wind resources, however, the weather significantly affects operating limits on intra-hour timescales, shorter than the hour-ahead timescales in which non-VRE suppliers can typically change their operating limits in ISO/RTO markets.[22] Standalone and hybrid VRE participation in reserve markets would likely require a more dynamic approach to calculating operating limits, as the CAISO has proposed in its *Hybrid Resources Final Proposal* (CAISO, 2020b). For instance, a wind facility's ability to provide reserves would depend on day-ahead, hour-ahead, and 5-min forecasts and forecast accuracy.

VRE forecasts that are used in scheduling and dispatch are point estimates. In fact, though, these estimates are points along a statistical distribution, which can be parameterized using historical weather data. Prediction intervals from this distribution can be used to determine AS market participation limits for standalone and hybrid VRE resources. Resource owners could use prediction intervals to determine whether they want to take on the risk of imbalance costs or penalties for non-delivery of AS awards. System operators could use prediction intervals to determine reserve and unit commitment needs.

Because VRE forecast errors significantly fall as the dispatch interval approaches, both resource owners and system operators might be more inclined toward real-time, rather than day-ahead, participation of VRE in power regulation and spinning reserve markets. However, there is likely to be value in VRE participation in day-ahead AS markets to reduce day-ahead commitment costs, even if only a small portion of an individual resource's forecasted output is eligible to participate or if VRE owners are only willing to offer a small portion of their output for reserves. Because the correlation of VRE forecast errors decreases with the larger geographic area (Miettinen and Holttinen, 2017), system operators may be able to deal with day-ahead VRE forecast errors by procuring reserves from a larger number of VRE resources over a wide geographic area. This approach would require more transparent and rigorous ISO/RTO reserve procurement methods.

Due to solar and wind generation variability and forecast uncertainty, ISO/RTO continuous duration requirements for reserves may also create a barrier to standalone and hybrid VRE participation in AS markets. Four of the seven ISOs/RTOs have explicit continuous duration requirements, typically lasting 30 or 60 min, for power regulation resources (Table 6), though some ISOs/RTOs allow limited energy storage resources that are only used for power regulation to meet a 15-min continuous duration requirement.[23] Spinning reserves also tend to have 30-min or 60-min duration requirements. Reconsidering these requirements, for instance, by reducing day-ahead scheduling intervals to 15 min or better matching product duration requirements with unit commitment processes, may be an important part of ISO/RTO efforts to enable VRE participation in AS markets.

Policies to support renewable generation, such as RPS requirements and tax credits, and contractual constraints may create barriers to VRE participation in AS markets, by biasing resources toward energy generation rather than reserve provision or by creating constraints on the operation of VRE facilities. These constraints would be expected to

Table 6
Continuous duration requirements for power regulation and spinning reserves by ISO/RTO.

	Power Regulation Reserve	Spinning Reserve
CAISO	Day-ahead: 60 min Real-time: 30 min	30 min
ERCOT	Unspecified	Unspecified
SPP	60 min	60 min
MISO	60 min	60 min
PJM	Unspecified	30 min
NYISO	Unspecified	Unspecified
ISO-NE	60 min*	60 min

Note: ISO-NE allows resources that do not meet this threshold to provide power regulation on a case-by-case basis by stipulating that "any Resource with less than 1-h sustainability must participate in the Power regulation test environment" (Independent System Operator – New England, 2021).
Sources: CAISO (2021); Electric Reliability Council of Texas (2020); Southwest Power Pool (2020); MISO (2020); PJM (2021); NYISO (2019); Independent System Operator – New England (2021).

[22] "Non-VRE suppliers" here refers to resources that do not have forecast-based bids. Changes in operating limits are typically made through real-time markets, which close roughly an hour before the operating hour.

[23] Examples include CAISO, MISO, NYISO, and SPP.

reduce reserve provision by standalone VRE facilities, though likely not to zero.[24] Additionally, with higher VRE penetration and potentially more curtailment, resource owners may be more willing to participate in AS markets. To avoid creating uneconomic grid operating constraints, particularly as VRE penetration increases, it is important to make sure that policy design is aligned with desired market outcomes.

5.2. Market impacts

Changes in power regulation and spinning reserve market volumes (procured quantities) and prices will impact the value of VRE participation in these markets. Both volume and price are expected to change in uncertain ways as VRE penetration increases.

Higher VRE penetration has two opposing effects on market prices for power regulation and spinning reserves. On the one hand, higher penetration reduces energy market prices and, thus, opportunity costs. On the other hand, it leads to more frequently binding operating constraints and higher power regulation and spinning reserve prices. For instance, when all online thermal generation has been reduced to minimum generation levels, power regulation down prices would likely be high. In the 2030 price projections used in the high VRE penetration sensitivity (Section 4.4), the net of these two effects was significantly higher power regulation prices. However, these forecasts did not include significant energy storage levels and assumed that VRE was not eligible to provide power regulation.

Power regulation and spinning reserve markets are relatively thin. In 2017, ISOs/RTOs procured an average of around 60–800 MW (0.3–0.9% of peak demand) of power regulation reserves and 600–2600 MW (1–4% of peak demand) of spinning reserves (Table 7). Increasing the scope of eligible resources — particularly energy storage — that can participate in these markets should lead to saturation. As a reference point, ISOs/RTOs had more than 130 GW of standalone and hybrid storage in their interconnection queues at the end of 2020, relative to total power regulation and spinning reserve requirements of 4.8 GW and 7.8 GW, respectively (Table 7). Even if 10% of storage projects in interconnection queues eventually come online, this suggests that reserve markets could saturate quickly over the early 2020s.[25] Market saturation would lead to lower reserve prices and reduced incremental reserve market value for VRE owners.

Table 7
Recent (2017) Power regulation and Spinning Reserve Procurement and Energy Storage in Interconnection Queues at the End of 202, by ISO/RTO and Total.

ISO/ RTO	Regulation Reserve Requirement (% Peak Demand)	Spinning Reserve Requirement (% Peak Demand)	Energy Storage in Interconnection Queue	
			Standalone Storage	Hybrid Storage
CAISO	RU: 320 MW (0.6%) RD: 360 MW (0.7%)	800 MW (1.6%)	22,712 MW	37,339 MW
ERCOT	RU: 318 MW (0.5%) RD: 295 MW (0.4%)	2617 MW (3.8%)	12,779 MW	7638 MW
SPP	RU: 470 MW (0.9%) RD: 325 MW (0.6%)	585 MW (1.1%)	5734 MW	3579 MW
MISO	425 MW (0.4%)	740 MW (0.6%)	2536 MW	2674 MW
PJM	Off-p: 525 MW (0.4%) On-p: 800 MW (0.6%)	1505 MW (1.0%)	14,898 MW	8046 MW
NYISO	217 MW (0.7%)	655 MW (2.2%)	11,889 MW	268 MW
ISO-NE	60 MW (0.3%)	900 MW (3.8%)	3645 MW	237 MW
Total	4817 MW	7802 MW	74,193 MW	59,781 MW

Sources: RU and RD are upward and downward power regulation, respectively. Off-p and On-p are off-peak and on-peak. Total power regulation is the sum of upward and downward power regulation, meaning that NYISO, for instance, has 217 MW of upward and downward power regulation and 434 MW of total power regulation. For PJM, we take the average of off-peak and on-peak power regulation. Power regulation and spinning reserve requirements are from Denholm et al. (2019). Interconnection queue data are based on data from Rand et al. (2021).

In principle, higher VRE penetration would be expected to increase the amount of power regulation and spinning reserve procured by ISOs/RTOs, to address higher sub-5-minute variability (power regulation) and larger wind and solar forecast error (spinning reserve). In practice, however, the relationship between VRE penetration and reserves is complex and depends on calculation methods and assumptions, product designs, and market designs (Milligan et al., 2010; Ela et al., 2011b; Andrade et al., 2016). For instance, higher VRE penetration will likely require dynamically calculated reserve needs (Ela et al., 2011a; Holttinen et al., 2012), but whether this increases total reserve procurement and its effect on reserve prices is unclear. As an example, the CAISO increased power regulation procurement in 2016 to manage rising amounts of solar generation (California Independent System Operator, 2017; Mills et al., 2021), whereas AS procurement in ERCOT, SPP, and MISO have been stable even with significant increases in wind generation (Zarnikau et al., 2019; Tsai, 2021). Changes in ISO/RTO market design, such as consolidation of ISOs/RTOs into larger balancing areas or improved market-to-market coordination between ISOs/RTOs, could also offset increases in reserve requirements.

The net effect of these different considerations on the incremental value of AS market participation for VRE owners is uncertain, which creates risks for VRE developers that are expecting to rely on AS markets as a core part of future revenues.

5.3. New AS values and services

This analysis's values and AS products were limited to power regulation and spinning reserve. New emerging AS products could provide additional sources of revenue to VRE owners beyond these two products. Potential new AS values and services could include:

- **Indirect reduced curtailment.** Nelson et al. (2018) showed that using solar PV to provide reserves could increase the value of solar by reducing curtailment that results from minimum thermal generation constraints. This effect is not captured in our analysis. Nelson et al.'s analysis was for a vertically integrated utility that is not part of an ISO/RTO. Understanding the potential magnitude of this effect for both standalone and hybrid VRE in ISO/RTO markets would require a market-wide analysis.
- **Ramping products.** CAISO (flexible ramping), MISO (ramp capability), and SPP (implementing in 2021) have upward and downward ramping products that aim to better position units to meet forecasted ramping needs, incorporating net load uncertainty, over future real-time dispatch intervals. Wind can currently provide ramp capability in MISO and any dispatchable resource with a real-time economic bid can, in principle, provide flexible ramping in CAISO.[26] Ramping products were designed to address relatively infrequent ramp

[24] For instance, adding a $25/MWh production tax credit to our analysis reduced power regulation provision by standalone VRE in CAISO in 2018 by about half.

[25] Between standalone and hybrid storage, 10% of projects would imply more than 13 GW of nameplate storage capacity, relative to a current power regulation market (upward + downward) size of around 5 GW and a spinning reserve market size of around 8 GW.

[26] In 2021, Potomac Economics, MISO's market monitor, recommended removing eligibility for wind resources to provide ramp capability, arguing that using wind to provide ramp will exacerbate other system constraints (PE, 2021a).

scarcity events, and thus ramping constraints tend to bind infrequently and the total value of ramping products tends to be low. In CAISO, for instance, flexible ramping constraints bound in less than 6% of all real-time dispatch intervals (15-min market) and total payments were around $9 million, relative to $148 million in total AS costs, in 2019 (CAISO, 2020a).[27]
- **Reliability capacity and imbalance reserves.** As part of its day-ahead market enhancements, the CAISO has proposed reliability capacity and imbalance reserve products (CAISO, 2020c). Reliability capacity is similar to the CAISO's existing residual unit commitment (RUC) except that, unlike RUC, the reliability capacity would be procured in the day-ahead market and have separate upward and downward products. Separate upward and downward imbalance reserve products would address differences between the day-ahead forecasted hourly net load and the real-time (15-min) net load forecast. The CAISO proposed allowing VRE to provide downward reliability capacity and downward imbalance reserves. The potential magnitude and value of these products are uncertain.
- **Primary frequency response (PFR) and fast frequency response (FFR).** Although the recent trend has been to require these kinds of capabilities as part of interconnection standards (Ela et al., 2011a; FERC, 2018), ISOs/RTOs may eventually introduce new products for PFR and FFR (synthetic inertia) that compensate resources, including VRE, for the opportunity cost of providing frequency response services. ERCOT, for instance, introduced an FFR product as a subset of its responsive reserve service in 2020, though eligibility will be limited to storage in phase 1. The amount of these products that ISOs/RTOs procure would likely be limited in size. Total primary frequency response obligations are less than 1% of peak demand in most ISOs/RTOs (around 2% in ERCOT) (Denholm et al., 2019), and these obligations do not scale with system size or VRE penetration (Denholm et al., 2020). ERCOT capped its FFR product at 450 MW (PE, 2021b). Potential prices for PFR and FFR products are uncertain.

In general, the average value of these emerging AS products to VRE owners is likely to be small, relative to energy and capacity value.

6. Conclusion

Standalone and hybrid VRE resources are not currently participating at meaningful levels in U.S. ISO/RTO markets for frequency regulation and spinning reserves. This paper examined the value of power regulation and spinning reserve market participation from a VRE owner and an electricity system perspective.

For standalone VRE owners, the results suggest that the incremental revenues from providing power regulation and spinning reserves would vary significantly across ISO/RTO markets, across years, and between solar and wind. For some resources in some markets, the average incremental value may be non-trivial. For instance, average (2015–2019 market prices) incremental revenues for providing power regulation services in CAISO (solar/wind), ERCOT (solar/wind), and SPP (wind) were $1.4–3/MWh$_{PC}$ (+6–15%). In other markets and for solar in SPP, incremental revenues were $1.0/MWh$_{PC}$ (+3%) or less. Power regulation markets are, however, relatively thin (<800 MW in each direction), and even in ISOs/RTOs with higher incremental value expanding market participation to VRE and energy storage may lead to market saturation and a decline in AS prices.

Participating in spinning reserve markets added little incremental value for standalone VRE owners, outside of ERCOT and, to a lesser extent, CAISO. This result underscores that, in most markets, most of the reserve market value for standalone VRE owners would be in providing power regulation reserves, though differences between ERCOT and other markets suggest that this result is sensitive to differences in market design and AS procurement practices. The high VRE penetration sensitivity showed significant increases in the incremental value of power regulation market participation for standalone VRE, due to higher power regulation prices and a higher frequency of hours in which power regulation prices exceed energy prices.

At current market prices, revenues from power regulation and spinning reserve markets are not large enough to meaningfully offset declines in solar and wind resources' energy and capacity value as their penetrations increase. As a reference point, Seel et al. (2018) estimate declines in energy value on the order of $5-$15/MWh in CAISO, ERCOT, SPP, and NYISO in 2030 with 40% combined wind and solar penetration. At higher VRE penetrations, power regulation and spinning reserve market revenues may more meaningfully reduce value declines in some markets. For instance, in the high VRE penetration sensitivity here (2030 price forecasts), incremental revenues from power regulation service in SPP ranged from $6/MWh$_{PC}$ (wind) to $15/MWh$_{PC}$ (solar). However, the price forecasts on which the high VRE penetration sensitivity are based did not include higher levels of energy storage, which would tend to depress power regulation prices. Relying on high future AS prices to fill revenue gaps will present risks for VRE developers.

For hybrid VRE owners, incremental revenues were, as expected, several-fold higher than for standalone owners, though variation across markets highlights differences in storage value due to different market designs and resource mixes. In the near term, the results suggest that AS revenues could be a significant part of hybrid VRE business models, with the POI sensitivity showing that most of the power regulation value of hybrids could be captured with POI capacity limited to the VRE facility's nameplate capacity when storage is sized to 50% of VRE capacity. However, hybrid VRE faces the same uncertainty around AS market prices that standalone VRE does.

In most ISOs/RTOs, standalone and hybrid VRE participation in power regulation markets could provide significant value to the electricity system as a whole, as measured by the difference between VRE resources' average power regulation value and average power regulation market prices. In other words, VRE could provide power regulation during periods with high market prices, which would put downward pressure on average market prices and provide ISOs/RTOs with a larger toolset to resolve emerging, higher-cost system constraints. The results show that, in general, VRE provision of power regulation services in ISOs/RTOs with separate upward and downward power regulation products was higher than in ISOs/RTOs with bidirectional products. Hybrid VRE provided more power regulation service and often, but not always, had higher power regulation value than standalone VRE.

Based on these findings, we emphasize the importance of implementing regulatory and market policies that better accommodate the integration of VRE resources into AS markets. Developing separate upward and downward power regulation products for ISOs/RTOs that do not have them will enable more efficient use of VRE and storage resources in power regulation markets by taking advantage of distinct opportunity costs for upward and downward reserves, as well as the weak correlation between upward and downward power regulation prices.

Focusing initially on VRE hybrid participation in AS markets, similar to CAISO's strategy (CAISO, 2020b), may be a more efficient first step toward expanding market participation, given that hybrids provide more reserves than standalone VRE and generally have higher AS value. Ultimately, enabling both standalone and hybrid VRE resources to participate in AS markets will offer greater flexibility and diversity to the system, allowing ISOs/RTOs to manage emerging, higher-cost system constraints more effectively.

By implementing these recommendations, regulatory and market policy can maximize the potential value of VRE resources and enhance overall system performance.

[27] The CAISO made revisions to its flexible ramping product in 2019–2020 that will take effect in October 2021. See https://stakeholdercenter.caiso.com/StakeholderInitiatives/Flexible-ramping-product-refinements.

Author contributions

J.H.K. led the research execution. J.H.K. and F.K jointly designed the study and wrote the paper. A.D.M and R.W acquired the funding for this research. A.D.M and R.W. provided overarching research direction and methodology design. W.G. and C.C.M. developed the hybrid dispatch model.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The authors do not have permission to share data.

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Appendix A. Supplementary data

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