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Variable Renewable Energy Participation in U.S. Ancillary Services Markets

Economic Evaluation and Key Issues

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October 2021

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Variable Renewable Energy Participation in U.S. Ancillary Services Markets: Economic Evaluation and Key Issues

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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 revenues 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 resource owner and electricity system perspectives, in each of the seven U.S. independent system operator and regional transmission organization (ISO/RTO) markets. Across ISO/RTO markets, average (2015-2019) simulated incremental revenues from 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 were able to provide regulation reserves during periods with high regulation prices, suggesting that VRE participation in AS markets could have high system value. The analysis highlights the value of separate upward and downward regulation products and suggests 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 to offset expected declines in energy and capacity value as VRE penetrations increase (Mills and Wiser, 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 regulation and contingency reserves (Ela et al., 2014; Loutan et al., 2017; Loutan et al., 2020; Rebello et al., 2020). Several studies have shown that wind generators can increase their revenues by providing 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). Wind generation is participating in regulation markets in the United Kingdom and reserve markets in Spain (Edmunds et al., 2019).

In the United States, however, VRE participation in organized AS markets is currently low or nonexistent and many questions around the economic value of VRE participation in these markets remain unanswered. For instance, how would the economic value of AS market participation to resource owners and to the electricity system as a whole compare between solar and wind generation, between standalone and hybrid VRE, across the seven organized electricity markets, and between different AS products? How might the economic value change with higher VRE and storage penetrations? What changes in market rules would be needed to allow VRE to participate in AS markets?
This paper examines the economic value of VRE participation in AS markets from resource owner and electricity system perspectives across the seven U.S. electricity markets. The analysis uses a price-taker dispatch model with simple, consistent assumptions that facilitate comparisons across technologies, VRE configurations, and markets over time. 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 regulation markets using historical market prices, with interconnection capacity limits sized to the VRE facility's nameplate capacity. It also examines sensitivities in which VRE participates in spinning reserve markets, VRE participates in future regulation markets in electricity systems with higher renewable penetration, and where interconnection capacity limits are sized to the maximum output of the combined generator and battery capacity (for hybrids). The paper closes with a discussion of three key issues for the results: barriers to VRE participation in AS markets, the potential impacts of higher VRE and storage

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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.

penetrations on the results, and other emerging AS opportunities for VRE not considered in the analysis.

2 Background

2.1 Key Differences in ISO/RTO AS Markets

U.S. independent system operators (ISOs) and regional transmission organizations (RTOs) procure six main kinds of AS products: regulation reserves, spinning reserves, non-spinning reserves, ramping reserves, voltage support, and black start capability. ISOs/RTOs procure 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. The focus in this paper is on the highest value AS products that are procured through competitive markets across all ISO/RTO markets: 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. In terms of AS products, a key distinction among ISOs/RTOs is in their procurement of regulation reserves. CAISO, ERCOT, and SPP separately procure upward and downward regulation reserves, whereas the other four ISOs/RTOs procure regulation reserves as a bi-directional product. In the latter case, a resource providing regulation reserves must hold an equal amount of 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 no co-optimization (ERCOT).[3] ISOs/RTOs that have 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.

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

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

Table 1. Current (2020) ISO/RTO Reserve Products and Procurement Practices

ISO/RTO	AS Reserve Products	Procurement Practices	AS Price Cascading
CAISO	Regulation up, regulation down, spinning, non-spinning	Co-optimized procurement of energy, regulation, and spin/non-spin procurement in day-ahead and 15-minute markets	Regulation price ≥ spinning price ≥ non-spinning price
ERCOT	Regulation up, regulation down, responsive, non-spinning	Co-optimized procurement of energy, regulation, responsive, and non-spinning reserves in 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	Regulation up, regulation down, spinning, supplemental	Co-optimized energy, regulation, and operating reserve procurement in day-ahead and real-time markets	Regulation price ≥ spinning price ≥ supplemental price
MISO	Regulation, spinning, supplemental (MISO is currently developing a separate short-term reserve product)	Co-optimized energy, regulation, and operating reserve procurement in day-ahead and real-time markets	Regulation price ≥ spinning price ≥ supplemental price
PJM	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 regulation procurement (PJM is currently developing day-ahead and real-time co-optimization for all reserves)	Synchronized price ≥ non-synchronized price
NYISO	Regulation, 10-minute spinning, 10-minute non-	Co-optimized energy, regulation, and operating	10-minute spinning price ≥ 10-minute non-

	synchronized, 30-minute spinning, 30-minute non-synchronized	reserve procurement in day-ahead and real-time markets	spinning price ≥ 30-minute operating price
ISO-NE	Regulation, 10-minute spinning, 10-minute non-spinning, 30-minute operating	Six-month-ahead but no day-ahead procurement; co-optimized real-time energy and operating reserve procurement; separate real-time regulation procurement (ISO-NE is currently developing day-ahead reserve procurement)	10-minute spinning price ≥ 10-minute non-spinning price ≥ 30-minute operating price

Notes: ERCOT’s responsive reserves and PJM’s primary synchronized reserves are both spinning reserves. SPP and MISO’s supplemental reserves and PJM’s and NYISO’s non-synchronous reserves are non-spinning reserves. Sources: This information is based on a review of ISO/RTO tariffs and manuals. See CAISO (2021); ERCOT (2020); SPP (2020); MISO (2020); PJM (2021); NYISO (2019); ISO-NE (2021). Price cascading information is also based on Giacomoni et al. (2018).

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, 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 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]

Another key difference in AS pricing among ISOs/RTOs, not shown in Table 1 , is scarcity pricing. ISOs/RTOs have taken different approaches to scarcity pricing in reserve markets, though all ISOs/RTOs use some form of administrative scarcity pricing. Administrative scarcity prices increase the price of reserves and energy above marginal cost during intervals of reserve shortage. ISOs/RTOs differ in their maximum scarcity prices, their design of scarcity price curves, and how scarcity pricing cascades across energy and reserve products. For more detailed descriptions of differences in ISO/RTO scarcity pricing mechanisms, see FERC (2014), Chang et al. (2018), and Harvey (2020).

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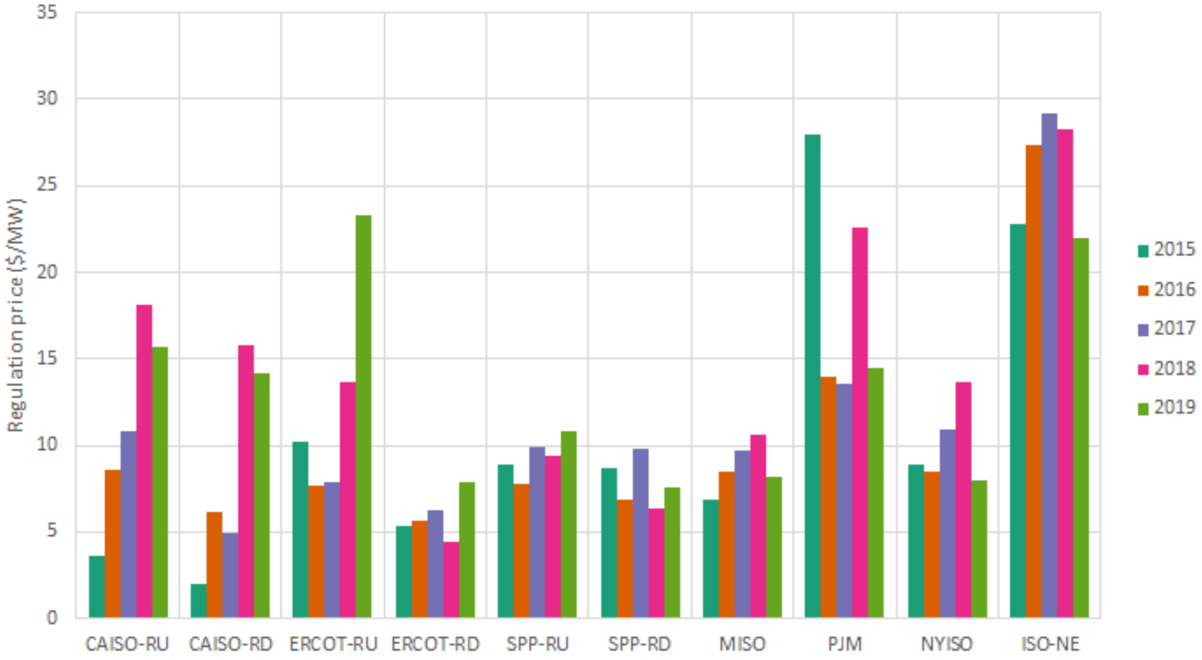
[4] For instance, for the zonal prices used in this analysis, day-ahead spinning reserve prices exceeded day-ahead regulation up prices in more than 90% of hours in ERCOT in 2018; in ISO-NE and PJM, real-time spinning reserve prices exceeded regulation prices in 1% and 3% of hours, respectively, in 2018.

[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).

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. Figure 1 illustrates AS price differences, showing average zonal regulation prices from 2015 to 2019 used in this analysis.[6] Figure 1 also illustrates the significant year-to-year variation in 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 regulation prices in ERCOT in 2019 resulted from high demand, which drove tight supply conditions (PE, 2020). The increase in regulation prices in CAISO between 2015 and 2016-2019 was driven by an increase in regulation procurement by the CAISO starting in 2016, along with growing challenges with procuring downward regulation reserves from conventional sources (Mills et al., 2021).

Figure 1. Average zonal regulation prices used in this analysis by ISO/RTO, 2015-2019



Notes: RU refers to regulation up, RD refers to regulation down. The figure shows simple averages. Consistent with our analysis, the figure shows real-time 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.

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).

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

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 can 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; Loutan et al., 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 regulation reserves between 14:00 and 15:00 at a day-ahead 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 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 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 regulation and spinning reserves would require curtailment of 5-minute forecasted generation, though the provision of upward regulation energy and contingency dispatch energy would provide an additional revenue source. Standalone VRE provision of downward

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[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 regulation reserves (SPP, 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 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] Regulation energy refers to the actual energy or curtailed energy (MWh) provided by a resource with a 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.

regulation reserves would not require curtailment of real-time forecasts, though the provision of downward regulation energy and corresponding reduction in energy generated would reduce revenues. For instance, a standalone solar PV facility providing 10 MW of upward 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-minute forecast when real-time dispatch is run (e.g., 14:00:00 or 14:02:30). If the 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 regulation energy (hourly equivalent), its total settlement in that interval will be $133 (= [10 MW × $30/MW + 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-minute 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-minute 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 cost. In addition, most ISOs/RTOs have separate clearing prices for mileage,[11] which compensate regulation providers for their performance in response to automatic generation control (AGC) signals. Of these three elements of AS pricing, opportunity cost tends to be the largest component.

Standalone VRE resources have near-zero variable cost, which means that, putting aside renewable energy credits (RECs), production tax credits, and other incentives, their opportunity cost of providing upward reserves rather than energy will be close to LMP. 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 (other costs ignored). Over time, and as we assume in this analysis, generators could

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[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-minute interval was sustained for one hour. In this case, 50 MWh hourly equivalent would be 4.2 MWh (50 MW average output sustained for 0.08 hours) of metered energy over the 5-minute interval. Total settlement is divided by 12 to convert to the hourly equivalent settlement to a 5-minute settlement. We use hourly equivalents throughout this paper.

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

also incorporate expected earnings or costs from reserve energy in this decision. For instance, if a solar PV facility providing upward regulation reserves expects to be dispatched to provide energy equivalent to 25% of its regulation award on average, it would choose to provide upward reserves in the above example as long as the reserve price is greater than $15/MW. At this point, the generator will be indifferent to providing energy ($20 for 1 MWh of energy) or reserves ($15 for reserves plus $5 for reserve energy for 1 MW of reserves) in that interval.

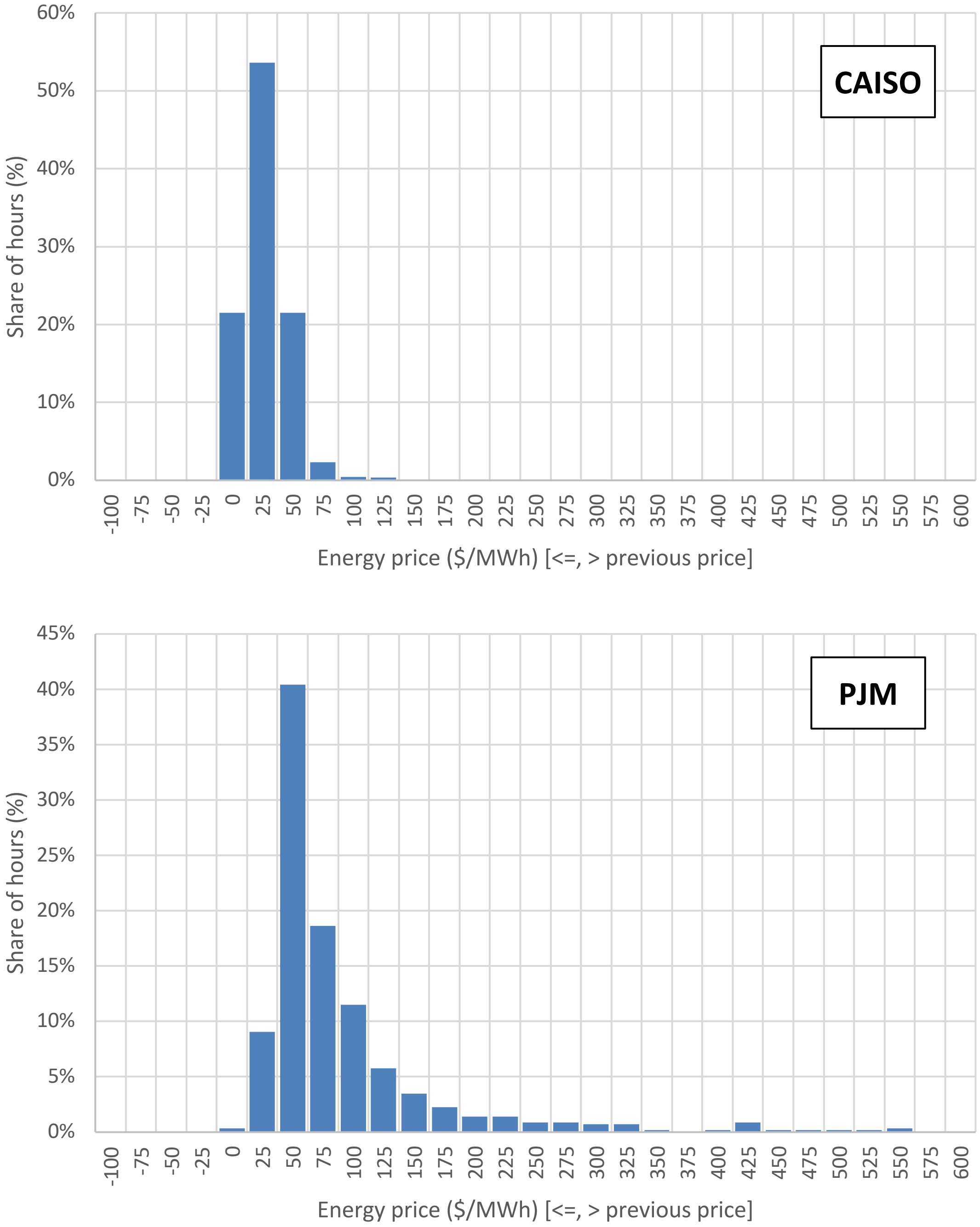
Downward regulation reserve prices are based on the incremental cost of keeping generators above their desired operating points. Standalone VRE resources' near-zero marginal cost thus means that their opportunity cost of providing downward reserves will be close to zero, because their desired operating point will almost always be their actual output. The only opportunity cost of VRE providing downward reserve will be lost revenue from regulation energy. For instance, if LMP is $20/MWh and expected downward regulation energy is 25% of the reserve award, a VRE facility would be willing to provide downward reserves as long as the reserve price is greater than $5/MW in that interval. At this point, the generator will be indifferent to providing energy ($20 for 1 MWh) or reserves ($20 for energy plus $5 for reserves minus $5 for reserve energy).

In cases where regulation is a bidirectional product and expectations for upward and downward regulation energy are symmetric, the breakeven condition for regulation reserve provision is that the regulation price must exceed the energy price, because the regulation energy benefits and costs will offset. For instance, consider a case in which a VRE facility is providing 10 MW of bidirectional regulation reserves over some real-time interval, faces a regulation price of $25/MW and an energy price of $20/MWh, and expects to provide 25% of its regulation award in upward and downward regulation energy. The $42 (= [10 MW × 0.25 MWh/MW × $20/MWh] / 12) that the facility will earn from upward regulation energy is offset by the $42 (= [10 MW × -0.25 MWh/MW × $20/MWh] / 12) that it will effectively pay from downward regulation energy and its expected revenues will be $21 (= [$25/MW × 10 MW + $500 - $500] / 12). If the 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, in markets where separate upward and downward regulation products exist, VRE will more frequently provide downward regulation reserves. 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 regulation (CAISO, ERCOT, SPP) or regulation (ISO-NE, MISO, NYISO, PJM) prices exceed energy prices vary across markets, from a low of 368 hours in MISO to a high of 2,205 hours in ISO-NE in our energy and AS price zones in 2018, though it was less than 1,500 hours (17% of hours) in all markets except for ISO-NE. In most markets, positive differences between 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. Figure 2 illustrates this difference in price dynamics, using CAISO and PJM as illustrative examples.

Figure 2. Share of Hours in Which 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 ≤ $50/MWh.

For hybrid VRE, the economics of energy versus reserve provision are 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 regulation and 10 MW of downward 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 regulation. The net income earned from energy arbitrage must therefore 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.

Regulation product design also affects the dispatch, and thus the economics, of VRE hybrids. In markets with bidirectional regulation products, regulation prices reflect the incremental cost of providing upward and downward regulation reserves simultaneously. However, in markets with separate upward and downward regulation products, upward and downward regulation prices tend to be weakly correlated.[12] This suggests that, in bidirectional regulation markets, resources with regulation awards will need to provide 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 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 renewable energy credits (RECs) or production tax credit (PTC) revenues from providing reserves rather than energy. We do not consider these factors in the analysis.

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[12] For instance, based on the AS prices used in this analysis, CAISO day-ahead upward and downward 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 regulation prices was 0.22; in SPP, the day-ahead correlation coefficient was 0.05 and the real-time correlation coefficient was 0.04.

3 Methods

This section describes analysis metrics and our modeling framework and assumptions. Section 8.2 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 $/yr
- *AS* is the VRE facility's annual AS market revenues, in $/yr
- G_{PC} is the pre-curtailment (PC) amount of annual generation from the VRE facility, in MWh$_{PC}$/yr
- 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 as a result of 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 regulation reserves mainly during system-constrained periods with high regulation prices will tend to have high unit value, relative to average upward 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 number of hours in the year (8,760 or 8,784)

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 regulation markets, as regulation tends to be the highest value AS product. In sensitivity analyses, we also consider participation in both regulation and spinning reserve markets and only in spinning reserve markets.[13] The model uses hourly average zonal energy, 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. For ERCOT, which did not have a real-time AS market during 2015-2019, the model uses day-ahead prices.

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

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[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).

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 regulation markets is 0.1 MW (PJM, 2021), ISO-NE's minimum size ranges from 0.1 MW (storage) to 5 MW (generation) (ISO-NE, 2021), and SPP's tariff does not stipulate a minimum size (SPP, 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 hybrids 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 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 regulation energy and contingency dispatch in their market bids, which is captured in the model's objective function. For regulation, we assume that the plant provides upward or downward regulation energy equivalent to 25% of its 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 hours 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 regulation energy in advance, which means that to factor 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

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[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.

[15] In principle, a battery that is charging/discharging at 10 MW could provide up to 20 MW of upward/downward 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.

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 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, or 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

4.1 Value to Standalone VRE Owners

Figure 3 and Figure 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 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 regulation products, price levels, and the relationship between energy and regulation prices. The incremental value for resource owners is generally higher in ISOs/RTOs with separate upward and downward regulation products (CAISO, ERCOT, SPP) than in ISOs/RTOs with bidirectional 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 regulation in most hours, whereas with bidirectional regulation products VRE will only provide downward regulation in a limited number of hours in which regulation prices are higher than energy prices.

Higher average annual 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 regulation prices than PJM during 2015-2019, but has higher incremental value because it has separate upward and downward regulation products.

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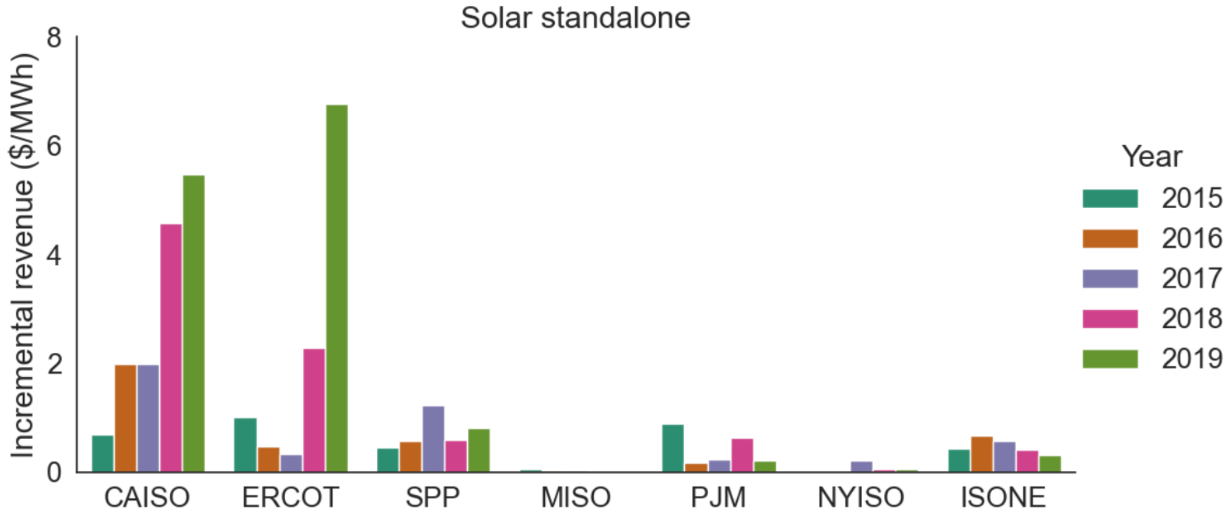
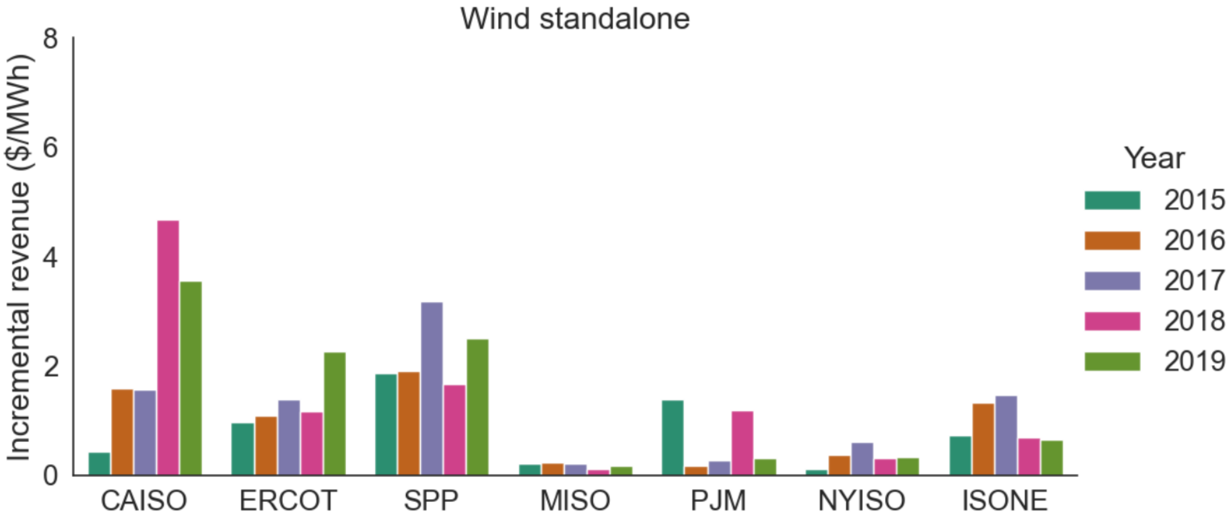
[19] We calculate percentage change in average revenues as the percentage difference between average unit revenues over 2015-2019 from providing energy and regulation reserves and average unit revenues over 2015-2019 from providing energy only. Because unit revenues in both cases are normalized by pre-curtailed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

Figure 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)



	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
2015-2019 average Δr	\$2.9/MWh	\$2.2/MWh	\$0.7/MWh	\$0.0/MWh	\$0.4/MWh	\$0.1/MWh	\$0.5/MWh
%Δ in average revenue	10%	6%	3%	0%	1%	0%	1%

Figure 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)



	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
2015-2019 average Δr	\$2.4/MWh	\$1.4/MWh	\$2.2/MWh	\$0.2/MWh	\$0.7/MWh	\$0.4/MWh	\$1.0/MWh
%Δ in average revenue	7%	7%	15%	1%	2%	1%	3%

In addition to regulation price levels, differences in results across years are also the result of changes in regulation procurement and the relationship between energy and regulation prices. For instance, CAISO increased its regulation procurement in 2016, leading to 1.4-fold and 2.1-fold increases in upward and downward 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 regulation prices relative to energy prices and an increase in the number of hours where regulation prices exceeded energy prices. As mentioned in Section 2.1, some of the changing 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 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 regulation in PJM in 2017.

4.2 Value to Hybrid VRE Owners

As Figure 5 and Figure 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 regulation price levels. For instance, MISO and SPP had similar real-time energy and 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 regulation products, which allows batteries to provide regulation more efficiently (see Section 2.2.2). For PJM and ISO-NE, higher regulation prices (Figure 1) explain why incremental revenues in these markets are higher than in MISO and NYISO.

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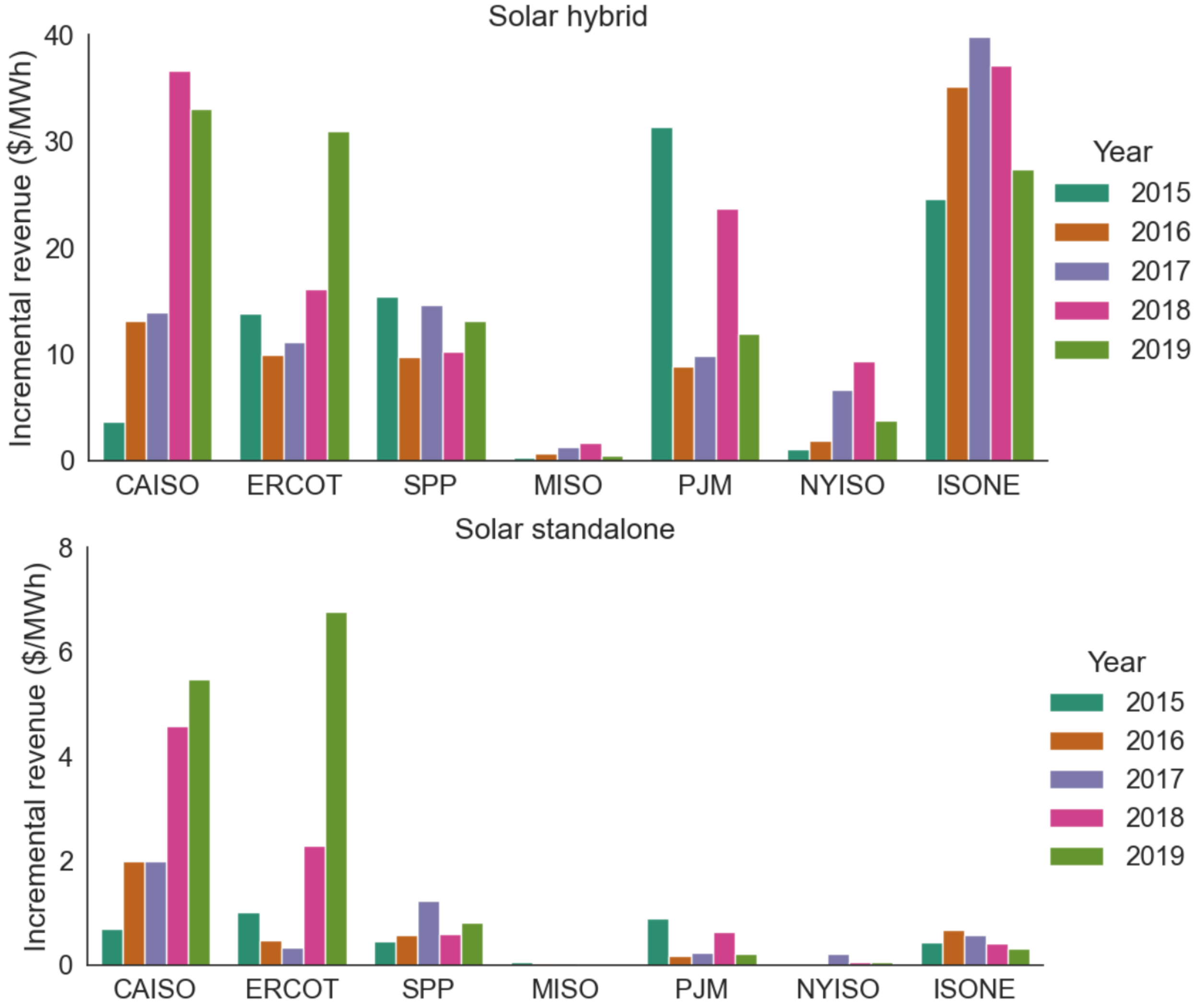
[20] For instance, based on the energy and AS prices used in this study, MISO's average real-time energy prices were $26/MWh ($C_V$ = 0.7) and its regulation prices were $11/MW-h ($C_V$ = 1.0), whereas SPP's average real-time energy prices were $24/MWh ($C_V$ = 1.0) and its upward and downward regulation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

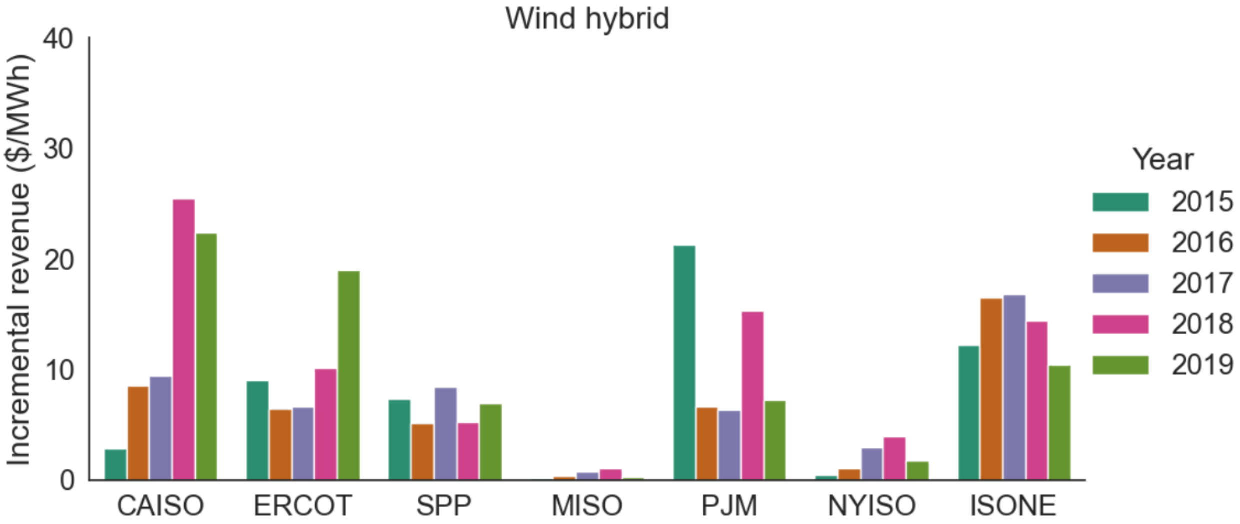
As with standalone VRE, differences between the solar and wind results are driven mainly by differences in resource profiles and capacity factors but are, to a much lesser extent, also influenced by the POI capacity constraints (see Section 4.4).

Figure 5. Incremental Revenue (\$/MWh$_{\text{PC}}$) to Hybrid Solar Owner (Figure), 2015-2019 Average Incremental Revenue (Table), and Percentage Change in 2015-2019 Average Revenue (Table)



	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
2015-2019 average Δr	\$20/MWh	\$16/MWh	\$13/MWh	\$1/MWh	\$17/MWh	\$5/MWh	\$33/MWh
%Δ in average revenue	48%	39%	36%	3%	37%	10%	69%

Figure 6. Incremental Revenue ($\$/\text{MWh}_{\text{PC}}$) to Hybrid Wind Owner (Figure), 2015-2019 Average Incremental Revenue (Table), and Percentage Change in 2015-2019 Average Revenue (Table)



	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
2015-2019 average Δr	$14/MWh	$10/MWh	$7/MWh	$1/MWh	$11/MWh	$2/MWh	$14/MWh
%Δ in average revenue	34%	41%	35%	2%	35%	7%	34%

4.3 Value to the Electricity System

Table 2 shows modeled results for both the regulation provision (*AR*) and regulation value (*v*) metrics, using 2018 ISO/RTO market prices.[21] 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 regulation the VRE facility will be providing regulation in both directions, which means that the "Total" regulation provision for markets with separate regulation products is comparable with twice the amount of regulation in markets with bidirectional regulation. Table 2 also shows simple average ISO/RTO regulation prices in 2018 (ISO AVG), as a point of comparison for the regulation value metric.

The results in Table 2 can be distilled into four key points. First, regulation provision is generally higher in the markets with separate upward and downward regulation products than it is in those with bidirectional regulation, even accounting for the fact that resources providing bidirectional 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 regulation, whereas a standalone wind facility in MISO provides only 0.3 MW (1%) of bidirectional regulation. In particular, having separate upward and downward regulation products

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[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.

allows VRE to provide downward regulation in situations in which, with bidirectional regulation, regulation prices would have needed to exceed energy prices to have made it cost-effective for VRE to provide regulation reserves (see Section 2.2.2).

Table 2. Simulated VRE Regulation Provision (*AR*) and VRE Regulation Value (*v*), Using 2018 Market Prices

		Regulation provision (*AR*, average MW), % capacity in parentheses				Regulation value (*v*) and ISO average regulation price in 2018 ($/MW)				
		Standalone		**Hybrid**		**Standalone**		**Hybrid**		**ISO AVG**
		Solar	**Wind**	**Solar**	**Wind**	**Solar**	**Wind**	**Solar**	**Wind**	
CAISO	**RD**	0.95 (5%)	0.91 (5%)	4.37 (44%)	4.23 (42%)	$26	$31	$31	$32	$12
	RU	0.42 (2%)	0.47 (2%)	3.92 (39%)	3.54 (35%)	$37	$62	$38	$40	$14
	Total	1.37 (7%)	1.38 (7%)	8.29 (83%)	7.78 (78%)	$29	$42	$34	$36	
ERCOT	**RD**	0.18 (1%)	0.82 (4%)	1.49 (15%)	1.45 (14%)	$8	$11	$14	$15	$4
	RU	0.24 (1%)	0.54 (3%)	3.09 (31%)	3.10 (31%)	$78	$16	$32	$32	$14
	Total	0.42 (2%)	1.36 (7%)	4.58 (46%)	4.55 (45%)	$48	$13	$26	$27	
SPP	**RD**	0.28 (1%)	1.32 (7%)	2.73 (27%)	2.42 (24%)	$12	$13	$15	$16	$9
	RU	0.15 (1%)	0.70 (3%)	2.43 (24%)	2.20 (22%)	$34	$14	$22	$23	$6
	Total	0.43 (2%)	2.02 (10%)	5.16 (52%)	4.63 (46%)	$19	$13	$18	$19	
MISO		0.03 (0%)	0.28 (1%)	1.22 (12%)	1.33 (13%)	$7	$6	$12	$12	$11
PJM		0.11 (1%)	0.27 (1%)	6.15 (62%)	6.00 (60%)	$67	$64	$26	$27	$23
NYISO		0.04 (0%)	0.38 (2%)	3.79 (38%)	3.05 (30%)	$10	$11	$15	$15	$14
ISO-NE		0.16 (1%)	0.51 (3%)	10.19 (102%)	8.26 (83%)	$34	$32	$21	$21	$28

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

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 both by resource profiles and the ISO/RTO resource mix, which is 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 for both standalone and hybrid VRE in bidirectional markets.

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

Fourth, the value for both standalones and hybrids is higher than ISO/RTO average regulation prices in almost all cases (MISO and NYISO standalones are the exceptions), which implies that VRE tends to provide regulation reserves during periods when regulation prices are higher than average. This result suggests that enabling regulation market participation by these resources would help to put downward pressure on average 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 regulation.
- **Energy + spin**, in which we only allow standalones and hybrids to provide energy and spinning reserve.
- **High VRE penetration**, in which we explore how incremental revenues (Δr) from regulation market participation might change with higher VRE penetrations.

For the first three sensitivities, we use 2018 ISO/RTO market prices. For the high VRE penetration sensitivity, we use 2030 energy and 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 four markets (CAISO, ERCOT, NYISO, SPP) in 2030.

Table 3 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 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 regulation markets (energy + reg + spin) or without participation in regulation markets (energy + spin) is low. This is partly due to price cascading, meaning that in CAISO, MISO, and SPP regulation prices will always exceed spinning reserve prices (see Table 1), and partly due to low spinning reserve prices relative to energy and regulation prices.

Table 3. 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. 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

Table 4 shows results for the high VRE penetration sensitivity, displaying incremental revenues (Δ*r*) 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 regulation prices are significantly higher in the High VRE scenario than in the Low VRE scenario. For instance, in SPP projected downward regulation prices increase from an average of around $4/MW-h to $27/MW-h. Second the frequency with which projected 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 regulation prices exceed energy prices increases from around 100 in the Low VRE scenario to around 1,500 in the High VRE scenario.

The results in Table 4 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 regulation and spinning reserve markets. For both standalone and hybrid resources, the most important barriers to participation in 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 the course of a day. For solar and wind resources, however, the weather has a significant effect on 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-minute 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 fall significantly as time approaches the dispatch interval, both resource owners and system operators might be more inclined toward real-time, rather than day-ahead, participation of VRE in 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 larger geographic area (Miettinen and Holttinen, 2017), system operators may be able to deal with day-ahead VRE forecast error by procuring reserves from a larger number of VRE resources over a wide geographic area. This would require greater transparency in and more rigorous methods for ISO/RTO reserve procurement.

ISO/RTO continuous duration requirements for reserves may also create a barrier to standalone and hybrid VRE participation in AS markets, due to solar and wind generation's variability and forecast uncertainty. Four of the seven ISOs/RTOs have explicit continuous duration requirements, typically lasting 30 or 60 minutes, for regulation resources (Table 5), though some ISOs/RTOs allow limited energy storage resources that are only used for regulation to meet a 15-minute continuous duration requirement.[23] Spinning reserves also tend to have 30-minute or 60-minute duration requirements. Reconsidering these requirements, for instance, by reducing day-ahead scheduling intervals to 15 minutes or by 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 reduce reserve provision by standalone VRE facilities, though

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[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.

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.

Table 5. Continuous Duration Requirements for Regulation and Spinning Reserves by ISO/RTO

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

Note: ISO-NE allows resources that do not meet this threshold to provide regulation on a case-by-case basis, by stipulating that "any Resource with less than one-hour sustainability must participate in the Regulation test environment" (ISO-NE, 2019).
Sources: CAISO (2021); ERCOT (2020); SPP (2020); MISO (2020); PJM (2021); NYISO (2019); ISO-NE (2021).

5.2 Market Impacts

Changes in 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 ways that remain uncertain, as VRE penetration increases.

Higher VRE penetration has two opposing effects on market prices for 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 regulation and spinning reserve prices. For instance, during periods when all online thermal generation has already been reduced to its minimum generation levels, 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 regulation prices. These forecasts, however, did not include significant levels of energy storage and assumed that VRE was not eligible to provide regulation.

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 regulation reserves and 600-2,600 MW (1-4% of peak demand) of spinning reserves (Table 6). 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 regulation and spinning reserve requirements of 4.8 GW and 7.8 GW, respectively (Table 6). Even if 10% of storage projects in interconnection queues eventually come

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

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 6. Recent (2017) Regulation and Spinning Reserve Procurement and Energy Storage in Interconnection Queues at the End of 2020, 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%)	2,617 MW (3.8%)	12,779 MW	7,638 MW
SPP	RU: 470 MW (0.9%) RD: 325 MW (0.6%)	585 MW (1.1%)	5,734 MW	3,579 MW
MISO	425 MW (0.4%)	740 MW (0.6%)	2,536 MW	2,674 MW
PJM	Off-p: 525 MW (0.4%) On-p: 800 MW (0.6%)	1,505 MW (1.0%)	14,898 MW	8,046 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%)	3,645 MW	237 MW
Total	4,817 MW	7,802 MW	74,193 MW	59,781 MW

Sources: RU and RD are upward and downward regulation, respectively. Off-p and On-p are off-peak and on-peak. Total regulation is the sum of upward and downward regulation, meaning that NYISO, for instance, has 217 MW of upward and downward regulation and 434 MW of total regulation. For PJM, we take the average of off-peak and on-peak regulation. 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 regulation and spinning reserve procured by ISOs/RTOs, to address higher sub-5-minute variability (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 regulation procurement in 2016 to

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

manage rising amounts of solar generation (CAISO, 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

The values and AS products considered in this analysis were limited to 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 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-minute 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 would have separate upward and downward products. Separate upward and downward imbalance reserve products would address differences between day-ahead forecasted hourly net load and the real-time (15-minute) net load forecast. The CAISO proposed allowing VRE to provide

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[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).
[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.

downward reliability capacity and downward imbalance reserves. The potential magnitude and value of these products is 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 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 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 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. 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 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 regulation market participation for standalone VRE, due to higher regulation prices and a higher frequency of hours in which regulation prices exceed energy prices.

At current market prices, revenues from 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, 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 regulation service in SPP ranged from $\$6/\text{MWh}_{\text{PC}}$ (wind) to $\$15/\text{MWh}_{\text{PC}}$ (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 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 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 regulation markets could provide significant value to the electricity system as a whole, as measured by the difference between VRE resources' average regulation value and average regulation market prices. In other words, VRE could provide 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 regulation services in ISOs/RTOs with separate upward and downward regulation products was higher than in ISOs/RTOs with bidirectional products. Hybrid VRE provided more regulation service and often, but not always, had higher regulation value than standalone VRE.

The results provide insights on two priority areas for considering VRE participation in ISO/RTO reserve markets. First, developing separate upward and downward regulation products, for ISOs/RTOs that do not have them, will enable more efficient use of VRE and storage resources in regulation markets by taking advantage of the fact that these resources have very different opportunity costs for upward and downward reserves and that prices for upward and downward regulation tend to be poorly correlated. Second, and similar to the CAISO's strategy (CAISO, 2020b), focusing initially on VRE hybrid participation in AS markets may be a more efficient first step toward expanding market participation, given that hybrids will provide more reserves than standalone VRE and will generally have higher AS value. That being said, ultimately it may be beneficial to enable both kinds of resources to participate in AS markets.

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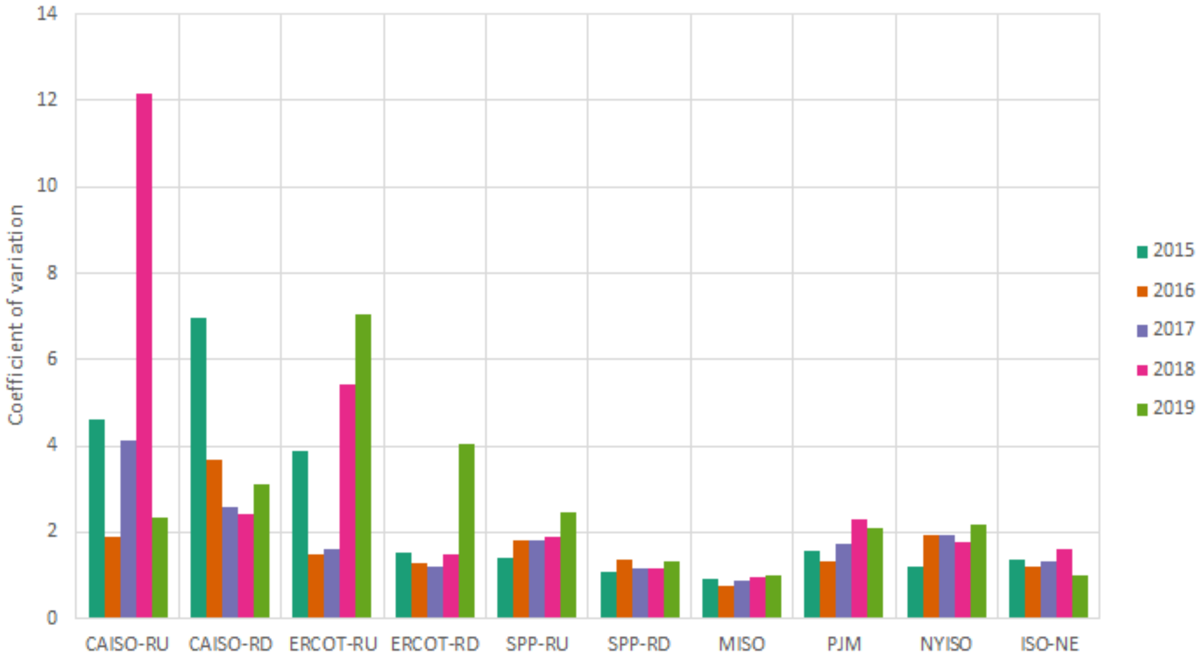
8 Appendix

8.1 Regulation Price Variance

Section 2.1 notes that "AS prices and price volatility vary significantly across ISOs/RTOs." Figure 7 shows the coefficient of variation (C_V, standard deviation of regulation prices divided by the mean) for regulation market prices by ISO/RTO. C_V values differ significant across ISOs/RTOs, but clearly the largest differences are between CAISO and ERCOT, on the one hand, and the other ISOs/RTOs, on the other. Differences in price variance among markets may play a role in explaining the results, particularly for hybrids, but the fact that SPP has relatively low regulation price variance but high incremental value (Δ*r*) suggests that other factors are at play.

Figure 7. Coefficient of variation for regulation prices used in this analysis by ISO/RTO, 2015-2019



Notes: RU refers to regulation up, RD refers to regulation down. Prices are for real-time markets except for ERCOT, for which prices are for the day-ahead market.
Source: Prices are from Velocity Suite. See Section 8.3 for AS price zones.

8.2 Model Formulation

The analysis in this paper uses a linear optimization model that maximizes wholesale market revenue against energy and reserve prices for hybrid and standalone VRE.

Hybrid Model

The optimization model for hybrid VRE is described in Eqs. 1-15. For hybrid VRE, only the battery provides reserves, assuming that the storage reserve value is much larger than VRE reserve value. The objective is to maximize net revenue (Eq. 1), considering cycling-induced storage degradation, which is the second part of the objective equation, and adjusted energy revenue by participating in the AS market, which is the third part. The linear penalty on cycling the battery reflects the degradation costs of deploying batteries in the wholesale electricity energy (D_e) and AS markets (D_r and D_s). This penalty essentially sets a minimum threshold for the battery for energy and AS market participation. The adjusted energy revenue is explained in detail in section 3.2. In markets with bidirectional regulation, we add an additional constraint to require that the facility provide upward and downward regulation in equal amounts.

The state of charge accounts for the trip efficiency (η) as well as the energy adjustment from participating in the AS market (Eq. 4). When the hybrid system participates in energy and AS markets simultaneously, the sum of energy and AS provision power profile does not exceed the storage power capacity (Eqs. 6 and 7). The sum of energy and AS provision energy profile must account for the sufficient energy capability based on the state of charge in the last time step (Eqs. 8 and 9). Eq. 10 represents spin duration rule to secure sufficient energy readiness of the system to provide spin for multiple time steps, if required.

On the constraints for electricity profile for the hybrid system, Eqs. 11-13 account for AC grid balancing of the hybrid system. These constraints warrant that VRE generation profile and battery charging/discharging match the energy input/output from/to the electricity grid, bounded by the POI capacity limit. Eq. 14 allows for the curtailment of VRE generation when prices are not favorable.

Objective function:

$$
\begin{aligned}
&Max \sum_{1}^{8760}\left[P_{rt} * G_i\tau + \left(P_{regup} * AS_{regup} + P_{regdn} * AS_{regdn} + P_{spin} * AS_{spin}\right)\right] \\
&\quad - \left[D_e * (B_d + B_c)\tau + D_r * \left(AS_{regup}\tau * \gamma_{reg} + AS_{regdn}\tau * \gamma_{reg}\right) + D_s * AS_{spin}\tau * \gamma_{spin}\right] \\
&+ \left[P_{rt} * \left(AS_{regup}\tau * \gamma_{reg} - AS_{regdn}\tau * \gamma_{reg} + AS_{spin}\tau * \gamma_{spin}\right)\right] \qquad \text{(Eq. 1)}
\end{aligned}
$$

Subject to:

Beginning state of charge: $S_0 = 0$ (Eq. 2)

State of charge range: $0 \le S_k \le E_{max}$ (Eq. 3)

Battery state of charge:

$$
\begin{aligned}
S^k = {} & S^{k-1} + \left[\eta B_c^k\tau - \frac{B_d^k\tau}{\eta}\right] \\
& + \left[\eta AS_{regdn}^k\tau\gamma_{reg} - \frac{AS_{regup}^k\tau\gamma_{reg}}{\eta} - \frac{AS_{spin}^k\tau\gamma_{spin}}{\eta}\right] \qquad \text{(Eq. 4)}
\end{aligned}
$$

Non-simultaneity rule: $B_d^k + B_c^k \le B_{max}$ (Eq. 5)

Power in rate: $B_c^k + AS_{regdn}^k \le B_{max}$ (Eq. 6)

Power out rate: $B_d^k + AS_{regup}^k + AS_{spin}^k \le B_{max}$ (Eq. 7)

Sufficient energy to discharge: $(B_d^k\tau + AS_{regup}^k\tau + AS_{spin}^k\tau)/\eta \le S^{k-1}$ (Eq. 8)

Sufficient room to charge: $\left(B_c^k\tau + AS_{regdn}^k\tau\right) * \eta \leq E_{max} - S^{k-1}$ (Eq. 9)

Spin duration rule: $AS_{spin}^k * UP_{spin} \leq S^k + \sum_k^{k+UP_{spin}} W^k\tau$ (Eq. 10)

AC-grid balance: $G_i^k = W^k + B_d^k - B_c^k$ (Eq. 11)

Grid charging limit: $-I_g B_{max} \leq G_i^k$ (Eq. 12)

Point of interconnection limit: $AS_{regup}^k + AS_{spin}^k + G_i^k \leq \text{POI}$ (Eq. 13)

Curtailment allowance: $W^k \leq G_{VRE}^k$ (Eq. 14)

Non-negativity: $B_d^k, B_c^k, AS_{regup}^k, AS_{regdn}^k, AS_{spin}^k \geq 0$ (Eq. 15)

Where the decision variables are:

G_i = hourly net electricity profile of hybrid or standalone system (MW)
B_d = battery discharging (MW)
B_c = battery charging (MW)
S^k = battery state of charge at time step k (MWh)
W^k = power generated from renewable resource at time step k (MW)
AS_{regup} = regulation up reserve from hybrid system (MW)
AS_{regdn} = regulation down reserve from hybrid system (MW)
AS_{spin} = regulation down reserve from hybrid system (MW)

And where the input parameters are:

P_{rt} = hourly real time electricity (\$/MWh)
P_{regdn} = hourly regulation down reserve price (\$/MW)
P_{regup} = hourly regulation up reserve price (\$/MW)
P_{spin} = hourly spinning reserve price (\$/MW)
D_e = degradation penalty for energy throughput(\$/MWh)
D_r = degradation penalty for regulation throughput (\$/MWh)
D_s = degradation penalty for spin throughput (\$/MWh)
B_{max} = battery max power capacity (MW)
E_{max} = total energy capacity of battery (MWh)
η = battery one-way efficiency (unitless)
γ_{reg} = regulation energy served fraction (unitless)
γ_{spin} = spin energy served fraction (unitless)
I_g = binary indicator to allow grid charging (i.e., 1 allows grid charging, 0 restricts charging to available VRE)
POI = Point of interconnection limit (MW)
G_{VRE} = standalone VRE generation profile (MW)
UP_{spin} = spin provision duration (h)
τ = interval duration (h), always equivalent to 1h in this study

Standalone Model

We designed a separate optimization model to estimate the generation and AS dispatch profile of a standalone VRE system (Eqs. 16-20). Eq. 18 sets the limit and condition of AS provision by the standalone system; for standalone VRE, wind and solar can provide reserves equivalent to 20% of their hourly profiles and a minimum of 1 MW (5% of nameplate capacity). The eligible minimum AS provision capacity is proportional ($C_c = 0.20$) to the generation profile of that hour (G_{VRE}). The condition under which the standalone system can provide AS, represented in parentheses, is when the eligible minimum AS provision capacity exceeds a certain threshold, proportional ($C_t = 0.05$) to the total nameplate capacity of the VRE system (20 MW). In markets with bidirectional regulation, we add an additional constraint to require that the facility provide upward and downward regulation in equal amounts.

Objective function:

$$Max \sum_{1}^{8760}\left[P_{rt} * W_i\tau + \left(P_{regup} * AS_{regup} + P_{regdn} * AS_{regdn} + P_{spin} * AS_{spin}\right)\right]$$
$$+\left[P_{rt} * \left(AS_{regup}\tau * \gamma_{reg} - AS_{regdn}\tau * \gamma_{reg} + AS_{spin}\tau * \gamma_{spin}\right)\right] \qquad \text{(Eq. 16)}$$

Subject to:

Curtailment rule: $W^k + AS_{regup}^k + AS_{spin}^k \leq G_{VRE}^k$ (Eq. 17)

AS provision rule: $AS = 0 \;\; \text{if} \;\; G_{VRE}^k * C_C < G_{max} * C_T$ (Eq. 18)

$AS \leq G_{VRE}^k * C_C \;\; \text{if} \;\; G_{VRE}^k * C_C > G_{max} * C_T$

Spin duration rule: $AS_{spin}^k * UP_{spin} \leq \sum_{k}^{k+UP_{spin}} W^k\tau$ (Eq. 19)

Non-negativity: $W^k, AS_{regup}^k, AS_{regdn}^k, AS_{spin}^k \geq 0$ (Eq. 20)

Where the decision variables are:

W^k = power generated from renewable resource at time step k (MW)
AS_{regup} = regulation up reserve from standalone system (MW)
AS_{regdn} = regulation down reserve from standalone system (MW)
AS_{spin} = spinning reserve from standalone system (MW)

And where the input parameters are:

P_{rt} = hourly real time electricity ($/MWh)
G_{max} = Nameplate generation capacity of renewable resource (MW)
G_{VRE} = standalone VRE generation profile (MW)
γ_{reg} = regulation energy served fraction (unitless)
γ_{spin} = spin energy served fraction (unitless)
UP_{spin} = spin provision duration (h)
Ct = threshold proportional to the nameplate capacity to be eligible to provide AS

C_c = eligible AS provision proportional to the nameplate capacity of the standalone system
τ = interval duration (h), always equivalent to 1h in this study

8.3 Data Sources

The analysis relies on two primary data inputs: VRE generation profiles and locational price profiles. To determine the location for solar and wind facilities, and in turn their generation profiles and locational energy and AS prices, we use an algorithm to select solar and wind plants that are located closest to the centroid of total solar or wind capacity deployed in 2019 and are consistent with average capacity factors in the ISO/RTO market in question. If the plant's modeled capacity factor exceeds a 10% margin from the average of (capacity-weighed) modeled capacity factors for plants in that market, the next closest plant to the average capacity-weighted centroid per ISO/RTO is selected if within the 10% margin, and so on. Hence, representativeness in this context is understood as a plant geographically close to actual renewable plant deployment and whose modeled capacity factor is within a certain margin of average modeled capacity factors in the selected ISO/RTO territory.

Table 7 shows selected plants for each technology and market, their latitude and longitude, and the corresponding energy trading hub and AS price zone.

To develop solar PV generation profiles, we use historical weather data from the National Solar Radiation Database for each location and weather year, to create a PV profile in NREL's System Advisor Model (SAM) assuming a single-axis tracking facility and an inverter loading ratio of 1.3. For wind profiles, we use average 2018 power curves from Wiser et al. (2020) and wind speeds from European Centre for Medium-Range Weather Forecasts' (ECMWF's) ERA5 weather data product. To use the ERA5 data, we first remove long-term bias in the ERA5 wind speeds for individual plants. To debias wind speeds, we use generation records from the first 2 to 5 years of existing wind plants to find the implied average wind speed from recorded generation, and we then scale ERA5 wind speeds to match this indicated average wind speed. We apply these scaled ERA5 wind speed time series to our typical power curve to calculate hourly wind generation profiles for each location and weather year.

To create price profiles, we match the solar and wind facility locations with energy price nodes (trading hubs) and AS price zones for each ISO/RTO. Wholesale energy prices for the plants are from the nearest major trading hub and the nearest AS price zone (see Table 7). Although historical ISO/RTO prices are available in the public domain, for convenience, we use the Velocity Suite data aggregator service from Velocity Suite.

Table 7. Solar and Wind Plants Used in the Analysis and Corresponding Trading Hub and AS Zone

ISO/RTO	Tech.	Plant	Lat.	Long.	Trading Hub	AS Zone
CAISO	Solar	SEGS III	35.01	-117.56	TH_SP15_GEN-APND	AS_SP15_P
	Wind	Windstar 1	35.05	-118.35	TH_SP15_GEN-APND	AS_SP15_P
ERCOT	Solar	Castle Gap Solar Hybrid	31.26	-102.27	HB_WEST	ERCOT
	Wind	Turkey Track Wind Energy LLC	32.20	-100.27	HB_WEST	ERCOT
SPP	Solar	Antanavica Solar	42.25	-71.95	.Z.WCMASS	REST OF SYSTEM
	Wind	Saddleback Ridge Wind Farm	44.59	-70.38	.Z.NEWHAMPSHIRE	REST OF SYSTEM
MISO	Solar	Strawberry Point DPC Solar	42.68	-91.55	ALTW.AZ	MISO
	Wind	Northern Iowa Windpower II	43.36	-93.30	SMP.AZ	MIDCONTINENT ZONE 5
PJM	Solar	Baer Road CSG	41.80	-75.07	HUD VL (ZONE G)	HUD VL (ZONE G)
	Wind	Maple Ridge Wind Farm	43.79	-75.58	MHK VL (ZONE E)	MHK VL (ZONE E)
NYISO	Solar	Essex Solar Center	37.83	-76.80	DOMINION HUB	PJM-RTO ZONE
	Wind	Wildcat Wind Farm I, LLC	40.35	-85.84	AEP-DAYTON HUB	PJM-RTO ZONE
ISO-NE	Solar	Caprock Solar 1 LLC	34.98	-103.38	SPS_SPS	SPP ZONE 3
	Wind	Greensburg	37.55	-99.34	SECI_SECI	SPP ZONE 1