

**JOINT COMMENTS OF
THE CALIFORNIA WIND ENERGY ASSOCIATION, FIRST SOLAR, INC., and
THE VOTE SOLAR INITIATIVE
ON CAISO RENEWABLES INTEGRATION MARKET & PRODUCT REVIEW**

The California Wind Energy Association (CalWEA), First Solar, Inc. (First Solar), and The Vote Solar Initiative (Vote Solar) appreciate the opportunity to comment on the September 30th document, *Renewables Integration – Market and Product Review, Phase 1* (Proposal), and the October 5th stakeholder meeting to discuss it. Our comments are summarized below.

TOPIC	CalWEA/FIRST SOLAR POSITION
Reducing self-schedules – shorter-term actions	The CAISO should remove barriers to: (1) market entry for new flexible resources; and (2) economic-bid submission by other resources.
	The CAISO should be prepared to require specific bidding behaviors if market incentives and RA changes fail to stimulate the level of economic bids that the CAISO needs.
PIRP & DA scheduling of VERs	The CAISO should retain PIRP and extend it to intermittent Dynamic Transfer schedules.
	The CAISO should allow economic bids on PIRP schedules without any loss of monthly netting of imbalances.
	The CAISO should extend PIRP to cover VER DA schedules if it wants to encourage such schedules.
DA scheduling of VERs	The CAISO should not impose DA scheduling obligations on VERs, because the bilateral market is already addressing this through PPAs.
Energy bid floor	The bid floor should be lowered until it is symmetric with the bid cap; the floor price should at least allow VERs and other resources to capture their revenue losses.
Allocation of renewable integration costs	The CAISO should not allocate renewables integration costs to VERs without considering similar treatment for other operating costs and resource types.
System flexibility – longer-run actions	The CAISO should continue to focus on identifying the CAISO’s long-term operational needs under a 33% RPS.
	The CAISO should work with the CPUC and others to modify RA requirements to reflect those identified operational needs.
	The CAISO should consider other market timing and structure issues – e.g., one or more “Day-Of” markets – to mitigate forecast errors and renewables-integration needs.

In addition, while we do not offer detailed comments on the REM Regulation proposal, we support this and other “no regrets” actions to reduce market barriers to new resources that will increase both current and future market efficiency and operability of the system.

Reducing self-schedules – shorter-term actions

The CAISO’s latest 20% RPS studies found that the existing generation fleet can provide physically, at least, the operational flexibility needed by the CAISO. However, addressing those operational needs through the market will require additional economic bids from those resources.

There are several actions that the CAISO should take now to encourage submission of more economic bids. One key action, as described below, is reducing the decremental bid-price floor, so resources submitting such bids can at least recover their direct and opportunity costs to provide the service. As noted above, the CAISO should also continue to remove barriers to entry for demand and storage resources, which could be active in the market within a relatively short timeframe.

These measures may prove insufficient to make available to the CAISO the operational flexibilities of the existing fleet in sufficient quantity to ensure reliability; thus, CalWEA recommends that the CAISO be prepared to require certain bidding or other actions for RA or other resources.

Such requirements could be implemented with relatively little lead time (i.e., they would not require major equipment or software changes). Thus, the CAISO should first see what problems the market will resolve with the stronger signals that MRTU is now providing, along with the additional actions we recommend in these comments, and then consider additional requirements (along with other alternatives) if those actions do not provide the operating flexibility that the CAISO needs.

Putting the problem in perspective: The CAISO should consider several factors before determining whether additional action is needed at this time:

- **Activities in the bilateral market:** The market signals from the new MRTU market are already causing at least some buyers in the bilateral market to alter their contracting processes. As seen in the latest proposed SCE pro forma PPA, buyers are seeking additional bidding and curtailment flexibility from sellers in order to protect themselves from the economic consequences of must-run contracts.

As the CAISO's operational flexibility needs increase, that increase should naturally be reflected in market prices, providing additional incentives to Market Participants to provide at least some of the services that the CAISO needs. This, along with the RA program changes we recommend below, may obviate the need for the CAISO to impose economic-bid mandates, or reduce the nature or scope of any mandates that are eventually needed.

- **Additions to the "existing fleet":** The 20% RPS study did not consider the universe of new resources likely to be available over the next several years, assuming that the CAISO continues to remove barriers to their participation and revises RA rules to reflect its expected operation needs, as recommended below. These new resources may include: (1) energy storage resources; (2) demand-side resources; (3) new pumped-storage facilities; (4) more flexible imports; (5) new gas-fired resources that are likely to be more flexible than the old units that they will replace; and (6) operating flexibility from VERs themselves.

When those potential flexible resources are considered, along with the current energy and A/S Must-Offer Obligations, the CAISO may have sufficient resources to manage any operational challenges from increased VER penetration without significantly higher self-scheduling from existing resources that choose to refrain from economic-bid submission.

Additional information needed to support CAISO decisions: The CAISO should do more research, and provide more information, before determining whether additional action is needed to encourage self-schedules. For example:

- ***How does the current level of economic bids compare to those received before,*** e.g.: (1) under the old market structure; and (2) under MRTU, in the same months last year? In other words, are Market Participants submitting more economic bids as they become more comfortable with the new market structure?
- ***What levels of economic bids are submitted for different kinds of resources,*** e.g., by: (1) resource technology; (2) RA vs. non-RA resources; and/or (3) resource ownership or scheduling responsibility? How do those results match with the expected resource mix in 2012 or beyond? What are the barriers preventing their submission of economic bids, and are those barriers factors that the CAISO can or should address?
- ***What levels of economic bids are submitted for different seasons or times of day,*** and how does that compare with the expected hours or extent of the need for flexibility? For example, a CAISO need primarily for more decremental energy bids during Spring off-peak hours might dictate different solutions than a more widespread need in other hours as well, or for both upward and downward flexibility.

- **How would the results of the 20% RPS study differ generally with more realistic generation-mix assumptions**, i.e., the likely future (vs. existing) generation fleet?

PIRP and DA scheduling of VERs

Need for PIRP overall: SCE has been very vocal in its opinion that there is no need for PIRP, now that there is an official RPS requirement and LSE buyers are performing most of the scheduling function for new VERs. However:

- **All LSEs do not have the same ability to absorb the forecast uncertainty** associated with VERs as a large utility.
- **LSEs might not always be the scheduling entity for VERs.**
 - **Earlier LSE-VER contracts gave the VERs themselves the scheduling responsibility**, with Inter-SC Trades to deliver the power to the LSEs; the parties might decide later to return to the earlier framework, and then the suppliers would need PIRP.
 - **Elimination of PIRP would effectively force suppliers into contracting only with large LSEs**, and only if the LSEs take the balancing risk.
 - **The contracting structure for Dynamically Transferred resources is not yet clear.** Many import contracts provide for delivery at the intertie; delivery for DT resources could be either at the plant bus like internal resources (i.e., with the buyer taking the imbalance risk) or at the intertie (i.e., with the seller taking the imbalance risk).
- **PIRP continuity and expansion can promote accurate scheduling.** The PIRP framework was established, in part, to enable very accurate and consistent plant-specific forecasts for scheduling. This accurate forecasting would be enabled by PIRP vendor access to:
 - **A more comprehensive data set than any plant individually**, including global, regional, and localized data, not the least of which would be data from other plants in the same area that would not be available to other buyers and sellers; and
 - **Extremely sophisticated modeling and forecasting techniques** that could be beyond the resources of individual sellers, and buyers smaller than large IOUs.
 - **Consistency in forecasting methodology** between different plants.

Since the PIRP plant-specific forecasts are used as the basis for scheduling, they would lead to more accurate scheduling if they are more accurate than those that individual suppliers or LSEs. This, it would benefit the market to continue to rely on PIRP forecasts, and to extend use of those forecasts to operations as well, e.g., to DA schedules and Dynamic Transfer schedules.

In order to determine the accuracy benefits of PIRP forecasts, it would be a good start if the CAISO would provide additional data about PIRP forecasting accuracy. The CAISO has not updated its PIRP forecast-performance data in some time, and the results might indicate a particular course of action. For example, the Proposal states that most of the PIRP benefit comes from mitigation of forecast inaccuracies, but:

- How does the accuracy of the PIRP vendor forecasts compare to scheduling accuracy of non-PIRP intermittent resources?
- If the PIRP forecasts are truly non-biased, wouldn't the scheduling inaccuracies cancel each other out over time? Is the \$2-4/MWh benefit then mostly due to exemption from some uplift charges?

Comments on the PIRP options in the Proposals: We lean more toward the approach in Option 1 (minimal changes) at this time.

- **No changes should be made to limit or eliminate the basic PIRP structure at this time.** Such fundamental changes should not be made without more thorough consideration of the commercial and forecasting-accuracy benefits discussed above.
- **The CAISO should allow economic bids to be submitted on PIRP schedules.** This is an obvious accommodation that would allow voluntary bids to curtail VERs if they are compensated for resulting economic losses. However, this change should not remove PIRP imbalance protection if the CAISO accepts such bids, or barriers to those bids would remain.

This change would require adjustments to the PIRP methodology to recognize the voluntary curtailment; otherwise, the forecasting model would assume that the resulting lower production level was the most that the resource could generate, given the meteorological conditions at the time, and that would impair the accuracy of future forecasts. Instead, the model should substitute an estimate of the amount of energy that would have been produced, in place of actual production, in hours when output is curtailed pursuant to economic bids.

DA scheduling of VERs

Concept generally: The CAISO already estimates real-time wind and solar production in the DA market – presumably using the same forecasting methodology as used for PIRP – and uses that estimate to commit longer-start units to serve loads the next day. Thus, it is important to clarify that, like the economic-bid issue, any DA scheduling requirement for VERs is a market, not reliability, issue.

- **Forecast accuracy:** DA scheduling was not included as a PIRP feature, because there was doubt that even the accurate forecasting models contemplated for that program could be accurate enough to incur market risks. As noted above, it is unrealistic to expect that individual Market Participants can be as accurate in their forecasting as the CAISO – overall or on a plant-specific basis – particularly given more recent findings that VER-generation forecasting accuracy of significantly increases as the geographic diversity of those resources increases.
- **Forecast risk:** The DA Must-Offer Obligation for RA Resources covers only the RA Net Qualifying Capacity (NQC) of those resources – they are not required to offer capacity above that level even if they have it and it is expected to be fully available. This extra capacity can act as a buffer for such resources, protecting them against de-rates between DA scheduling and real-time operations.

Presumably, any DA scheduling requirement for VERs would only apply, similarly, up to the level of their NQC. It would be unfair in the extreme, and contrary to the rules of the RA program, to require them to schedule expected energy production above that level – or for the CAISO to create “proxy bids” above that level if no schedule is submitted – when they do not receive any RA credit for that additional capacity.

Conversely, if they were forced to schedule their actual forecasted output, they would be scheduling at a level that exceeds their RA value about 70% of the time, yet their imbalance risk would equal 100% of their schedule.

- **Lack of need:** As noted above, there is no operational need for VERs to schedule in the DA market. However, because of the strong market signals under the new MRTU framework, buyers and sellers are already recognizing the benefits of avoiding volatile real-time market prices by providing for DA scheduling in their PPAs. The CAISO should have sufficient confidence in its own market and see how those new contract provisions will mitigate its concerns before considering any further scheduling mandates.

If the CAISO believes that it is important to have VER schedules in the DA IFM, it can submit a “proxy” bid based on its forecast. We understand the CAISO’s reluctance to “participate” in the market in this manner; however, it is disingenuous for the CAISO to argue that it is not impacting the market in a similar manner when it considers this same forecast in the RUC process. The RUC process also impacts market prices; the CAISO should have the flexibility to manage VER impacts in the most efficient manner by using either the IFM or RUC.

- **Equity:** The CAISO has not explained why VERs should be subject to a mandatory DA scheduling requirement when other Use-Limited Resources (ULRs) are not. There is no logical reason for singling out VERs for this obligation.

Comments on CAISO options

- **Option 3:** The improvement and release of CAISO aggregate wind and solar forecasting data, perhaps broken down regionally, would seem to be a “no regrets” action. We support that course of action as long as individual suppliers cannot be identified.

- **Options 1 and 2**

- The CAISO has not justified imposition of a DA scheduling requirement for VERs: (1) at all; and/or (2) for VERs but not for other ULRs.
- Bilateral contracting for large utilities is already incorporating DA scheduling of VERs, and CAISO should give that process time to work before imposing any mandates.
- The CAISO should extend PIRP protection to VERs if any DA scheduling requirement is imposed. Any scheduling obligation should be limited only to a resource’s NQC.

Finally, as noted below, the CAISO should consider market timing and structural changes that would shorten scheduling and unit-commitment time horizons, to mitigate concerns about DA market performance and the need for integration resources.

Energy bid floor

The 20% RPS study expressed concerns about the CAISO having an adequate supply of decremental energy bids to manage real-time congestion and over-generation conditions, and the Proposal raises the possibility of lowering the current -\$30 decremental bid-price floor.

We have never understood the reasons for the current asymmetrical treatment of the energy bid-price cap and floor. There are numerous reasons why lowering the bid-price floor could elicit additional decremental energy bids; for example, it would allow suppliers offering such bids to be made whole for financial losses for:

- ***Take-or-pay or minimum-take gas or other fuel contracts;***
- ***Opportunity costs for hydro facilities spilling water instead of generating energy,*** or for other Use-Limited Resources (ULRs);

- **Minimum production guarantees or delivery obligations** in PPAs;
- **Loss of related industrial production** for CHP units;
- **Incremental wear-and-tear** from additional unit cycling; and
- **Loss of PPA payments and Production Tax Credits (PTCs)**, where applicable. (There was an inaccurate statement at the meeting that suppliers would be paid anyway if decremented in real time, so only the PTCs would be relevant; however, there are several common PPA provisions that place curtailment consequences from real-time bidding on the supplier, including those: (1) allowing curtailment at some level without compensation by the buyer; and (2) placing full responsibility for real-time results on suppliers, depending on DA scheduling results.)

Moreover, lowering the bid-price floor would encourage new and existing suppliers to make capital investments to improve their operating flexibility, such as lowering their minimum operating points.

We have yet to hear a convincing reason for the large disparity between the bid-price cap and floor. In the absence of such arguments, the CAISO should select Option 2 – symmetrical bid-price cap and floor prices.

We would have no objection to lowering the bid floor in two steps, as posited in the Proposal – e.g., to -\$750 in the first year and -\$1,000 in the second, to match the current bid-price cap. Thereafter, unless there are strong arguments to the contrary, changes to the bid-price floor and cap should be made together.

Alternatively, the CAISO could use the current Independent Entity review used to set plant-specific Default Energy Bids to establish a resource-specific bid-price floor that reflects their specific PPA provisions and other relevant factors, so their floor price would reflect their revenue losses.

Allocation of renewables integration costs

The Proposal would “begin the dialog,” and conduct “a detailed review of options,” in this phase of integration activities. Recommendations would be deferred to Phase 2.

In considering the question of payment for integration resources, it’s important to keep in mind that the CAISO is not BPA. It is understandable that non-CAISO BAAs, like BPA, would consider integration charges, since development there is largely taking place to meet California RPS objectives, and those integration costs would otherwise be borne by those BAAs’ own consumers.

However, such charges are not needed for CAISO-area resources, because:

- **The CPUC is already considering integration “adders,” and other jurisdictional regulatory authorities are welcome to do the same.** There is no need for the CAISO to undertake what would likely be a contentious, imprecise, and duplicative effort in this area – that would only penalize VERs twice for the same integration costs (once through reductions in its PPA price, and then again through the CAISO charge assessment).
- **CAISO-area consumers will pay for integration services regardless.** If suppliers must try to estimate these costs and include them in their prices, they will undoubtedly need to build in extra margins to ensure that their costs are covered and that their plants can be financed. The uncertainty itself could be a factor in plant financing.

- **Imposing integration or A/S costs only on VERs would be discriminatory.** Much of the existing A/S requirements and costs are due to the performance of existing fleet – for example, operating reserve is procured to protect the system due to forced outages of conventional generators. However, the CAISO has made no attempt to determine the incremental cost of managing other resource types, and to assign that cost directly to those resources – that approach is being considered only for VERs, with costs for all other resources assigned directly to demand.

Moreover, as noted above, CAISO studies have not yet considered the impact of new A/S market entrants or and the ability of VERs to moderate their own impact through economic bids and perhaps other tools. It may well be that any additional integration services that the CAISO needs will both be less than the CAISO has estimated and cost less than the CAISO fears.

Thus, while options can be listed, and to some degree explored, we agree that it is premature to make any definitive recommendations or decisions in this phase of the effort. At this point, we would strongly oppose any effort to impose integration-services costs on VERs.

System flexibility – longer-term changes

We understand the CAISO’s desire to focus on short-term market changes in this part of the integration effort. However, short-term market initiatives and signals, even in a well-functioning market (let alone the overwhelmingly bilateral CAISO market), may not be enough to address long-term CAISO system integration needs under a 33% RPS, especially if those markets fail to explicitly account for the cost of carbon emissions. The CAISO should thus continue to focus on its current effort to identify the resources (and their characteristics) that will be needed to meet those long-term needs.

To ensure that the CAISO continues to have sufficient physical resources to meet those identified long-term operational needs, the CAISO should then work with the CPUC and other LSE oversight bodies to revise the applicable RA Requirements to reflect them – e.g., requiring that a certain portion of the RA requirement be met with Regulation-capable resources. The RA program has been the most important factor in ensuring supply adequacy in CAISO markets, and revising the program to include operational flexibility elements (along with the current A/S and energy Must-Offer Obligations) would do the same for integration-resource needs.

In that longer-term timeframe, the CAISO should consider larger market timing and structural changes as well. One beneficial change might be shifting the focus of the current Integrated Forward Market (IFM) from a Day-Ahead (DA) timeframe to a Day-Of (DO) timeframe; this shift could: (1) reduce load and VER forecast errors, and thus system flexibility needs; and (2) better use the much faster start-up and ramping capability of new conventional and other resources (demand response and storage resources). The CAISO could even consider running 3 to 4 DO IFMs at strategic hours of the day.