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Submitted by email to RI-MPR@caiso.com

RE: Comments of the Large-scale Solar Association on the <u>Discussion and Scoping Paper on Renewable Integration Phase 2</u>

The Large-scale Solar Association (LSA) [1] submits these comments in response to the CAISO's request for stakeholder views on its **<u>Discussion and Scoping Paper on Renewable Integration Phase 2</u>** (Paper), the April 5th document initiating the CAISO's Renewable Integration: Market and Product Review, Phase 2 (RIMPR-2) effort. Specifically, the CAISO has asked for input on the following topics:

- The proposed plan for Phase 2 as outlined in the Introduction, including the idea of a comprehensive market roadmap and a subset of topics to address this year.
- The completeness of the list of topics and issues for consideration in Phase 2 and inclusion in the roadmap and identification of other topics and issues that should be included.
- The high priority topics and issues for addressing this year

In addition, at the April 12 stakeholder meeting and in the paper, the CAISO also requested that stakeholders identify principles for decision-making in at least proposed topics, such as allocation of integration costs to variable energy resources (VERs). The CAISO intends to use stakeholder-suggested decision-making principles, as well as responses to the above questions, to establish a "roadmap" for future RIMPR-2 actions. Although these principles will presumably be revisited once the roadmap is established, we offer some initial thoughts in these comments.

Historically, renewable resources have been largely passive in the CAISO bid-based markets, treated as non-dispatchable price-takers. In the future, this may change, and these resources could become active participants to help resolve operational constraints and reliability needs. This move toward dispatchability and other operational capabilities will result, not only from potential integration charges and added incentives to submit energy and ancillary service bids, but also by improved operational capabilities, of the energy-producing equipment itself or enhancements such as storage or hybridization with other fuels, that would allow them to obtain additional value from the markets over time.

[1] LSA represents 13 of the nation's largest providers of utility-scale solar generating resources. Collectively, LSA's members have contracted to provide over 7 GW of clean, sustainable solar power to California's Load-Serving Entities. Its members develop, own and operate various utility-scale solar technologies, including photovoltaic and solar thermal system designs. LSA, and its individual member companies, are renewable energy industry leaders, advancing solar generation technologies and advocating competitive markets.

Moreover, if California policy goals are achieved, renewable energy could at times be the majority of energy produced in some hours of the day by 2020. Increased market participation by renewables may thus be desirable from both a cost and emissions perspective, at least until other resources, such as storage, are capable of providing these services in a manner consistent with policy goals. Large-scale solar plants are also important capacity resources for any future power system. Hence, this initiative offers the opportunity to take the critical first step of evaluating how best to re-design wholesale power markets around new characteristics of the high-renewables power system, and fully understand the implications of any potential market design changes given other regulatory considerations.

Summary of Priorities for 2011 and Beyond

LSA believes that the CAISO should distinguish between topics that can be completed in 2011 and topics where stakeholder discussion and analysis by the CAISO and other parties can begin intensively in 2011 but would conclude in 2012 or later. Some of the other topics could be re-visited later in 2011 once progress has been made on the higher priority topics.

- For completion in 2011, LSA recommends hourly contingency-only election for operating reserves, pay for performance regulation, and uneconomic adjustment priority for VERs.

Given the complexity of the remaining topics here, almost all of them are likely to take longer than the remainder of 2011 to reach conclusion, and hence need prioritization for 2012 and beyond. There may be value in identifying a smaller working group with sufficiently broad representation to work on this effort in support of CAISO staff.

- For initiation in 2011 but completion in 2012 (or beyond), LSA recommends design of a load-following reserve requirement and market, assessment of additional intra-hour markets, the evaluation of allocation of integration costs, and the evaluation of forward reserve markets (FRM) and centralized capacity markets (CCM).

- The other topics can be revisited and re-prioritized later in 2011. These include: operational and reliability requirements for system inertia and frequency response, multi-settlement for ancillary services, enhancements to RUC (which may be at least partly duplicative with procurement of additional load-following and regulation reserves day-ahead), and reflecting constraints in market prices.

Need for a Comprehensive Roadmap

LSA agrees that the topics presented in the discussion and scoping paper require a comprehensive, multi-year roadmap, with high-priority market design changes identified for each year. In addition to the summary above, we provide some initial views on each item below. The timing of particular market design changes could be further informed by additional simulations. For example, the CAISO's 20% RPS integration study was a snapshot of 2012, with assumptions about how much renewable energy would be located in-state (possibly more than is likely to be interconnected by that year) and out-of-state. That study's conclusions suggested that regulation and load-following requirements could be met by the existing generation fleet, possibly without any further changes to market design other than procurement of additional regulation. As a part of RIMPR-2 the CAISO should consider a process to update this study, or at least parts of it, on a regular basis as an indicator of when the major energy, ancillary service and capacity requirements and cost shifts are likely to take place. Such an assessment would also help renewable developers understand what capabilities are needed in particular time-frames and the market value of those capabilities.

Similarly, the timing of new markets or products to meet future capacity needs, whether through a CCM or FRM, should be related also to forecasts of the expected conditions in the State's RA program and the influx of renewable energy. The revived interest in a CCM and/or FRM stems from the recognition that significant revenue shifts will take place among generator classes at higher RPS and also that operational needs will be changing year to year such that older plants that may appear to be economically non-viable in an earlier year may be needed in later years to provide ramping and reserves and even backstop capacity. Hence, a primary purpose of a CCM and/or FRM is to provide more revenue stability over multiple years and improved price discovery for capacity value and possibly value of other attributes. However, if these products are introduced during a period of substantial capacity surplus, then prices would likely fall to a price floor, depending on the location (and a one-year product could be affected more adversely than a multi-year product). The result could be problematic if the CAISO's objective is to ensure revenue stability and prevent increased reliance on non-market solutions. Conversely, markets that are started during periods of capacity shortage, whether at a system level or in particular congested locations are likely to generate higher prices than expected or justified, if the appropriate anticipatory investment decisions have not been made (e.g., in transmission expansion or demand response). Given the high degree of market uncertainty given California's policy goals for the power sector, extreme care would be needed in any such market design decision.

In sum, a comprehensive road-map must address not just the market design logic of particular proposed reforms, but also consideration of their timing and likely market conditions.

Coordination with CPUC RPS and LTPP Proceedings

A critical requirement for CAISO market design in this new era is to understand how any new or modified market products and rules interact with the incentives and requirements in the CPUC RPS and LTPP proceedings, which are themselves in evolution, as well as the RA program and the CAISO's own transmission planning process. The RPS/LTPP and utility selection criteria for renewable project proposals are evolving to combine certain elements – including long-term renewable resource cost assessments, renewable technology market valuations in energy, capacity and integration, and overall integrated resource planning – that substantially overlap with CAISO long-term market-design objectives, namely to provide the right incentives to adapt technology and affect behavior to support economic dispatch, meet operational needs and ensure reliability.

For example, if any integration costs are charged to VERs, the CAISO must coordinate with the CPUC to ensure that those costs are not double-counted in the procurement process. It would be highly inequitable if integration costs were counted against VERs in the procurement process, on the assumption that those costs would be borne by ratepayers, and then the CAISO assessed those same costs against VERs in its markets – essentially charging VER suppliers twice for the same costs.

There is also a high potential for the wholesale markets to send the wrong or ineffectively timed price signal if integration requirements are addressed in long-term regulatory proceedings and transmission planning processes, and investment decisions made accordingly, but then costs are subsequently assigned to generators that were not provided contracts that provided revenues for any needed operational flexibility. For example, a PTO could rate-base transmission to increase the capability of a pumped storage plant to provide load-following and ancillary services, and then collect market revenues for those services, but then VERs could be denied the revenues to cover additional operational flexibility and charged for those integration service costs. This observation is made not to suggest that the transmission investment is unnecessary, but to recognize that coordination is necessary before new cost allocation structures are developed. LSA has further comments below on the need for consistency among regulatory and market based cost allocations.

Discussion of Specific Topics

LSA recommends that the CAISO apply the following objectives in assessing specific market design proposals:

- Support efficient wholesale market functioning, given renewable policy objectives;
- Focus on resource electrical and operating characteristics, and avoid discrimination by resource technology or type;
- Minimize costs for any additional ancillary services and load-following reserves associated with integration of VERs or other resources;
- Ensure that any *ex ante* or *ex post* calculation of the incremental integration costs associated with variable energy resources are determined through careful analysis, whether or not such costs are allocated directly to such resources through the CAISO markets;[2]
- Ensure alignment of market signals-based and revenue planning-based incentives for investments in integration capabilities;
- Provide opportunities for all generation and non-generation resource types to supply the flexibility and services the CAISO needs for reliable and efficient wholesale market operations.

Enhancements to Existing Market Design

LSA generally supports the objectives of the proposed enhancements to the existing market design, which are intended to increase flexibility into the ancillary services markets and improve RUC capacity procurement with higher levels of variable energy resources. However, we believe that only one of these enhancements should be put on the agenda for completion in 2011. Also, we note that RUC procurement of integration services or operational attributes might duplicate any additional procurement of incremental day-ahead ancillary services to meet integration needs.

[2] That is, the CAISO will be making both ex ante estimates of integration needs through its simulations and will be tracking actual procurement ex post. This information may not ultimately be used directly in cost allocation but could be used to make technology and project decisions by both buyers and sellers of renewable energy.

Hourly Contingency-Only Election for Operating Reserves

LSA supports this market modification. Utility scale solar projects with storage or hybridization may have the capabilities to offer operating reserves and hence would benefit from the flexibility offered by an hour-by-hour election of operating reserve designations.
This proposal could be evaluated and concluded in the 2011 time-frame.

Multi-settlement system for ancillary services

LSA supports further evaluation in 2011 of a multi-settlement system for ancillary services, for the reasons identified by the CAISO. In the future, with the growing forecast error associated with variable supply, the CAISO could at times be procuring much more than its actual ancillary service needs day-ahead; alternatively, it could attempt to procure less than 100 percent of forecast ancillary services day-ahead and the residual requirement closer to real-time as forecasts are updated. Sellers, including large-scale solar plants, will benefit from the capability to move between these markets.

LSA does not have an opinion on whether this proposal can be fully evaluated and concluded in the 2011 time-frame; regardless, this is not a priority issue for our members this year.

Enhancements to RUC

The CAISO has identified a number of important RUC issues to resolve in this initiative, some of which may overlap with other market design changes, such as procurement of additional regulation and load-following reserves in the day-ahead market. Whether RUC reforms are priorities in 2011, or pushed to later, is thus related in part to decisions made about these other design changes.

Some of the additional capacity required to address forecast errors for renewable production would presumably be procured under a day-ahead regulation and load-following reserve procurement. These day-ahead ancillary service procurements would be conducted on a probabilistic basis, unlike the current RUC. For example, as currently modeled in the CAISO simulations, the procurement requirements are based on multiple iterations of a statistical model that conducts random draws from a distribution of hour-ahead and real-time forecast errors or persistence forecasts; the capacity requirements then generated are selected to represent the 95th percentile of the forecast requirement. If some or all of the actual day-ahead procurement of reserves was conducted in the same way, presumably using day-ahead forecast errors, then it would account for the load-following and regulation capacity needed at the higher end of the forecast errors and would reserve additional capacity from the eligible suppliers of integration services. Hence, if another probabilistic estimate was conducted in the RUC, at least some or perhaps all of any additional RUC procurement for integration purposes could be duplicative.

The same types of concerns would arise if the RUC was used to procure operational attributes – these should be taken into account in any day-ahead procurement of load-following and regulation reserves.

Evaluation of this proposal could begin in the 2011 time-frame, but the CAISO will likely to need a longer period to conclude work if it is to be properly coordinated with related topics.

New spot market products

New market products could help reduce integration costs and provide improved incentives to large-scale solar plants and other resources to participate in the markets and invest in needed capabilities.

Pay for performance Regulation

Pay for performance Regulation could provide an incentive for more efficient provision of Regulation, which may in turn lead to lower ancillary service procurement costs and reduced greenhouse gas emissions associated with supply of Regulation. Pay for performance for regulation ramping may also provide a model for ramp payments in the real-time energy dispatch markets.

The CAISO has asked for views on calculation of inter-temporal opportunity costs as a component of the Regulation payment. In principle, such opportunity costs should be calculated and paid to ensure efficient supply. Since limited-energy storage resources (LESRs) are not expected to be optimized based on prices but rather on frequency of use (e.g., to maximize mileage payments), it is not clear how such an opportunity costs would be determined; however, the CAISO could consider whether dispatch through the new Regulation Energy Management mechanism could lead to some intertemporal opportunity costs during the hour, e.g., charging of the LESR during high-priced intervals or discharges during low-priced intervals, that warrant some payment adjustment.

LSA assumes that the timing of this initiative is related to expected FERC requirements rather than near-term market needs.

Load Following Reserve

LSA generally agrees with CAISO views on the need for further analysis of load-following requirements, including both empirical analysis of the inherent load-following flexibility of the dispatch on an ongoing basis and continued simulation of future needs. Although not discussed in the Paper, the 20% RPS report showed that load-following capabilities are also crucially related to self-scheduling, while subsequent data provided by the CAISO showed how different resources were scheduled on average. The CAISO should thus work to reduce self-scheduling to appropriate levels, given actual production constraints, prior to procurement of additional reserves. In the alternative, if the CAISO procures additional load-following reserves prior to reducing self-scheduling, the costs of such reserves should not be allocated to VERs, as discussed below.

With respect to the CAISO's questions on procurement of reserves, the operational simulations have made clear that the quantity of load-following reserves calculated is highly dependent on forecast error. Since such reserves must be provided largely from synchronized and quick-start resources, some quantity will have to be procured in forward markets, with the remainder procured closer to real-time, perhaps hour-ahead. Some ISOs/RTOs, such as ERCOT, are already procuring non-spinning reserves to follow wind production on a variable basis day-ahead using an exceedance forecast. CAISO procurement of such reserves on pre-day-ahead time-frames, e.g., as a means to support investment in operational attributes, should be determined in the context of the longer-term procurement issues discussed below.

Evaluation of this proposal could begin in the 2011 time-frame, but the CAISO will likely to need a longer period to conclude this work if it is to be properly coordinated with related topics.

System inertia and frequency response

In general, meeting system inertia and frequency response requirements through conventional generation will increase the minimum generation levels on the system and reduce the amount of renewable energy that can be integrated (without storage). Hence, LSA members have an interest in providing these capabilities to the extent possible. Some LSA members with solar thermal plants may be able to support system inertia using the attributes of their technology (rotating mass), while both solar thermal and PV plants can add system inertia and frequency response through investments in storage or hybridization.

LSA recognizes that this is a longer-term issue than the others on the Phase 2 agenda, but one that needs to be evaluated with sufficient time to consider all viable long-term solutions. The CAISO should re-examine prioritization of this issue for late 2011/early 2012 after the modeling results are available.

Flexible ramping constraint

LSA recognizes that the flexible ramping constraint is being presented as a short-term "fix" to load-following constraints while longer-term solutions are being evaluated. This topic is being presented for information purposes in the RIMPR initiative, and so we do not offer any views on prioritization.

Reflecting constraints in market prices

As a general matter, LSA agrees that reflecting constraints in market prices could be important for longer-term wholesale energy market efficiency, especially future system conditions with higher energy and ancillary services payments for services that do not set market clearing prices, such as for regulation mileage payments and increased numbers of starts, stops and operations at minimum operating levels (to provide upward reserves). Overall, energy market prices will be reduced somewhat due to the increased production by renewable resources, which in concert with the factors above could lead to significant dampening of market prices. If the CAISO sought to counteract this market impact, it would have two possible impacts on solar projects: on the one hand, it could increase the value of solar energy during peak hours (compared to the lower price that might emerge otherwise); on the other hand, it could create more volatility in real-time prices, increasing market price risk to variable energy resources. The latter topic has been addressed so far separately under the topic of PIRP reforms, but clearly, the issues raised here bear on decisions made on that topic.

LSA recommends that the overarching topic of reflecting constraints in market prices, including the MOC constraint and pending flexible ramping constraint, as well as other related topics, such as extended LMP methods, be examined further in 2011, while decisions on other changes to market settlements, such as PIRP reform, be postponed until there is further clarification of long-term market implications.

Allocation of integration costs

Allocation of integration costs to VERs is the topic of greatest interest and concern to LSA members in RIMPR-2, because of the potential impacts on renewable development and even the viability of some projects if such rules significantly increase to the already high level of regulatory and market risk in California. The CAISO has defined these costs broadly, and seeks ostensibly to provide economic incentives to renewable developers to make technological changes and investments (e.g., capability to respond to dispatch in real-time, storage or, depending on the technology, hybridization with other fuels) that reduce or address system operational requirements and also allow their scheduling coordinators to participate more extensively in the wholesale markets for energy and ancillary services. In principle, these are sound objectives.

LSA is aware of the need to address future operational requirements and integration costs and is committed to working with the CAISO, state regulators and LSEs to refine our collective understanding of what those requirements are and how they can be met cost-effectively with a mix of renewable resource design modifications, investments in other generation and non-generation resources, operational and scheduling changes, and other policy or market reforms. Because we expect this discussion to continue for several months if not years, we will limit our comments here to (1) whether this topic should be slated for completion in the 2011 time-frame, (2) some principles for market/regulatory design in this area, as requested by the CAISO, and (3) some initial comments on the questions posed by the CAISO.

With regard to the CAISO's scope of work for 2011, we believe that this topic will require at least 12-18 months for evaluation. Most renewable generation enters the California market through long-term contracts and integration costs will likely vary dramatically year by year, as they are a function in large part of the renewable resource mix. Multi-year integration cost analysis is itself a relatively new field, and most studies so far, with the exception of the CAISO's own analysis, have been confined to wind integration only. Indeed, the CAISO has only recently entered into a dialogue with the solar sector on modeling assumptions in its 33% RPS simulations, and that analysis has not even begun to examine the value of operational changes by different types of solar technologies (such as inclusion of storage in the project).

As such, there is still much work to be done to understand the properties of combined wind and solar systems at high RPS, including to clarify the drivers of integration requirements by different solar technologies. Just as importantly, as discussed below, there needs to be clear alignment between, and consistency among, any regulatory and market design decisions, which in themselves will take time to establish and refine. Hence, we believe that this topic cannot be resolved in 2011 and recommend that the initial effort over Q2-3 of 2011 should be to define a research agenda and provide sufficient time to complete the work. The overall timing of this work must accommodate careful evaluation of the impact on renewable development. The expectation should be that a CAISO draft final proposal would be forthcoming by no earlier than early/mid-2012.

We also believe that there is already sufficient focus on this topic from all sources that this time-frame for the CAISO's work will not prevent LSEs' from considering such attributes in their solicitations and renewable developers from beginning to develop responsive project proposals.

Moreover, the next round of 33% RPS solicitations will take place in 2011 before any CAISO rules are finalized.

The CAISO has asked for some principles to guide decision-making on this topic. LSA believes that the overarching goal is the integration of the renewable policy goals at the lowest overall cost to ratepayers. The process should carefully consider how any CAISO proposal interacts with the below factors in determining whether the proposal achieves that ultimate goal:

- Coordination with other regulatory processes impacting procurement and other infrastructure investment;
- Resolution of existing market inefficiencies;
- Accurate determination of VER integration costs that serve as a basis for such charges; and
- Consideration of the market impacts of such allocation.

<u>Coordination with other regulatory processes and market timing</u>: The first and possibly most important principle over the long-term is to ensure that regulatory decisions on infrastructure investments made outside the CAISO's purview, notably under the State's RPS, LTPP, and possibly RA programs, as well as those made under the CAISO's transmission planning process (or future FERC rules), are consistent and not duplicative with the market signals provided by any prospective cost allocations flowing from the CAISO markets. These State regulatory programs are attempting to incorporate integration costs directly or indirectly (e.g., in curtailment provisions) both in long-term RPS procurement decisions and in LTPP approvals. Operational attributes could also be considered in RA procurement in future years. The CAISO's planning process is also identifying transmission upgrades for PTOs to include in rate-base that would increase operational capability, and could in the future include certain types of storage as transmission assets. As a result, renewable developers could make inefficient investment decisions if they are required to anticipate wholesale market cost allocations while other entities are making long-term investments to serve the same purposes through other regulatory and planning processes. LSA thus recommends that the first step in understanding how integration requirements and costs should enter investment decisions be for the CAISO to hold a joint workshop on coordination of regulatory, planning and market design with the CPUC and CEC, with participation by market participants.

A second principle (that flows from the first principle) is that price signals need to be sent when they are most effective in eliciting the desired response. For example, signals that weigh features that direct favor toward one technology over another are best received in the LTPP, as the CPUC and LSEs are designing their long-term procurement processes. Price signals that may result in lost RPS energy (e.g., to address curtailment needs) would ideally be understood as the financial structure of a project is being developed so that the impacts can be built into the commercial arrangement. By the time of the real-time markets, the dimensions in which market participants can respond and their ability to financially accommodate such responses has narrowed significantly.

<u>Resolution of existing market inefficiencies</u>: A third principle is that before any decision to allocate integration costs to VERs, the CAISO and market participants should first resolve all existing inefficiencies in the wholesale markets that could contribute to higher integration costs, and also undertake other changes in operating procedures that could reduce integration costs.

The CAISO took a first step towards this in the 20% RPS report, by identifying that historical patterns of self-scheduling limit the quantity of load-following that may be available. An obvious example of an inappropriate cost to allocate to VERs would be CAISO costs to commit additional dispatchable resources to provide load-following while other flexible resources that could have otherwise provided that service are self-scheduled.

In addition, the impact of other sources of flexibility should be examined to find low cost solutions. For example, the 20% RPS report examined sensitivities of the simulation results to changes in assumed firm imports; while historically, imports would be expected to be cheaper energy than available from marginal in-state generation (although they will increasingly include some RPS energy), the cost of those imports in some hours could also include the cost of curtailing in-state renewable energy and the additional integration cost caused by firm import inflexibility. So, at least some imports in some hours might be considered higher-cost than currently understood as in-state renewable production increases. CAISO market prices may signal this over time, but possibly imperfectly in the absence of the right market design.

The CAISO should also initiate discussions to examine any other opportunities for low-cost provision of integration services, such as from hydro resources. And further, as discussed above, if a non-renewable supplier of integration services has been supported financially through non-market revenue streams, that should not be then re-charged to renewable resources as an integration cost.

<u>Determination of VER integration costs:</u> The CAISO must have a means of accurately determining such costs before charges are imposed. While studies released so far have shown a CAISO need for at least some additional Regulation and ramping services to manage VER penetration, the degree of that need has not yet been demonstrated. For example, these studies assume that all integration services must be provided by gas-fired generation, and the additional flexibility likely to be available from new resources like storage and demand-side actions has not yet been studied.

Moreover, any charges for integration costs should consider not only incremental requirements associated with VERs, but also integration costs for other resources. For example, the CAISO procures reserves to protect against contingencies (e.g., outage of the largest single resource in an area), and cost-causation principles dictate that resources besides VERs also be charged for the integration costs that they impose on the system.

<u>Market impacts of VER integration charges</u>: Integration costs must be covered, and arguably ratepayers will ultimately pay any such costs. However, the means by which those costs are covered can have impacts elsewhere in the market that could raise the impacts on ratepayers.

For example, integration costs could be covered through some combination of lower PPA payments to VERs, consideration in RA requirements (e.g., requirements that a certain amount of RA capacity be Regulation capable, or that LSE portfolios have minimum ramping capability), and explicit CAISO market charges. Each of these methods will impact ultimate consumer costs and should be carefully considered. If a renewable project has significant net revenue risk due to that penalty that it does not have the tools to manage, project financing parties are going to "assume the worst". In order for projects to overcome this hurdle, prices to ratepayers for the energy will be sufficiently high to ensure financers receive their needed rate of return in that worst-case scenario. Hence, market design changes that are not fully coordinated with regulatory and financial consideration could result in ratepayers paying for the worst-case scenario rather than the actual cost.

The CAISO has raised the following questions for the initiative and asked for comments. LSA urges that the CAISO refrain from making value judgments in the RIMPR documents while the technical details are being worked out.

1. Which specific integration costs should be allocated to VER?
First, for the reasons noted above, an analytical process is needed to determine what integration costs can be associated with VERs and what result from other factors, such as existing market and scheduling practices or reliability rules. Second, this question presumes that any incremental costs identified with VER should be allocated to them, but as discussed above, that is a complex policy question that needs to be answered in the context of California's regulatory structures and the incentives created there.

2. How should the relative cost shares charged to demand versus charged directly to VER be determined? For example, if VER should be charged for a portion of the cost of ancillary services, what methodology would be appropriate and fair for measuring the incremental impact of VER on this cost?
LSA reserves its opinion on the technical details of this topic, but notes that there are two general options: to determine these incremental costs ex ante, which would give project developers greater certainty in financing, but which would almost certainly be wrong when real-time requirements are calculated; or ex post, which would be more accurate but introduce substantial uncertainty into project development. These are key issues that need to be explored before any market design changes.

3. Should cost allocation be based simply on resource categories (e.g., technology, PMax), or should it be based on measured performance of each resource during the hours the costs are incurred?
Again, LSA reserves its opinion on the technical details of this topic, but notes that to determine technology specific costs ex ante would be very speculative, although clearly a plant with storage or hybridization with other fuels will have the operational capabilities to achieve lower integration costs than plants without those capabilities.

4. If measured performance is the basis for cost allocation, should these costs then be allocated to all resources, regardless of resource type, that exhibit the same performance to a lesser degree?
This question is not clear as written. If the question is whether all plants that exhibit, e.g., a similar forecast error because they are in a geographic location that has similar wind or insolation patterns, or simply by chance, should be put in a similar cost allocation bucket, that is the kind of technical issue that needs close examination. For example, there may be correlation of forecast errors among different locations that is not captured if each location is evaluated separately, but could affect total system requirements.

5. Should allocation of integration costs be limited to the operational and spot market areas, or should we also consider allocating some of the integration costs through the generation interconnection procedures (GIP)?
This issue is related to the question of whether integration costs can be calculated ex ante vs. ex post, and the question about whether impacts of particular technologies, and configurations of those technologies, can be adequately isolated in either case. LSA reserves its technical views on this topic, but notes that the CAISO should be extremely careful in advancing policy approaches

prior to consideration of all the factors discussed in this section, as significant commercial decisions could be contingent on any of these determinations.

Modifications to Intra-day market settlements

LSA supports a careful evaluation of additional intra-day markets that begins in 2011 but probably does not reach conclusion until 2012. One general trend already identified in the FERC notice of inquiry on VERs is that at higher RPS, there will be a value in wholesale markets that settle closer to real-time, reflecting the scheduling requirements of VERs as well as the evolution of the non-renewable resources – gas plants and storage – towards much greater operational flexibility, including quicker start and stop times and faster ramp rates. This could include moving the day-ahead market later in the prior day, as unit commitment will become less significant on day-ahead time-frames, and incorporating hour-ahead or multi-hour-ahead markets.

Full Hour-Ahead market

LSA believes that a full hour-ahead market could be useful to minimize exposure to imbalance charges and integration costs, depending on developments in other market rules, such as the PIRP. Historically, hour-ahead markets for conventional resources have been thin markets (other than imports), but that would likely change in power markets dominated by wind and solar resources. Renewable resources could benefit from an hour-ahead financial settlement for purposes of hedging imbalance charges in real-time.

Evaluation of this proposal could begin in the 2011 time-frame, but the CAISO is likely to need a longer period to conclude this work if it is to be properly coordinated with related topics.

15 minute market in real-time

The CAISO's description of a 15-minute market is unclear, but appears to propose that such a market is an alternative both to a possible full hour-ahead market (and existing HASP settlements) and to the current settlement of real-time dispatch at 5-minute prices. In other words, the CAISO would retain a two-settlement system composed of a day-ahead market and a 15-minute market. LSA believes that this is a concept worth exploring further, because it would allow for averaging of LMPs during what are likely to be very volatile 5-minute intervals at times of day, which VERs may prefer, particularly if the PIRP financial settlements are terminated. As noted, it would also facilitate coordination with imports that are being scheduled or bid on a 15-minute basis.

Evaluation of this proposal could begin in the 2011 time-frame, but the CAISO is likely to need a longer period to conclude this work.

Uneconomic adjustment priority for VERs

LSA supports further evaluation of a prioritization of resources when the CAISO conducts uneconomic adjustments. We agree with the CAISO that ideally, the market will provide sufficient bids to minimize uneconomic adjustments and that a lower bid floor will induce more participation by VERs.

Given that, providing any remaining VERs that have not submitted decremental bids with a higher priority would be consistent with public policy objectives. It would also reflect the fact that, given current long-term contracts, wind and solar energy also likely cost LSEs with RPS obligations more to curtail than conventional resources (at least in most circumstances), and renewable energy that required additional transmission upgrades for deliverability costs more than that from energy-only resources.

Hence, there appears to be some cost basis for prioritization. At the same time, the CAISO is correct to be concerned that a prioritization could reduce incentives to submit bids by VERs, especially at times of day. This issue will have to be addressed in this initiative.

Longer-term procurement issues

LSA commends the CAISO for including longer-term procurement issues in the proposed Phase 2 scope of work. Although much of the redesign of the California power system taking place under RPS implementation is being done through long-term contracting, there is still sufficient uncertainty about the attributes of future resources that complementary long-term wholesale market products will help to clarify the value of investments that improve capacity value and operational performance.

Capacity market

Capacity value is an important component of the economic benefits of large-scale solar PV and solar thermal projects, as well as perhaps the most significant market-based mechanism to provide economic incentives for investment in additional operational capabilities, such as storage or hybridization. Large-scale solar projects are resources that already produce at peak, making additional investments to improve capacity value potentially cost-effective. LSA supports a careful examination of the best market designs to support capacity valuation in the future. LSA is aware, however, that a CCM presents significant political and regulatory challenges at this time, and so we stop short of recommending that the CAISO begin such a design in Phase 2, and certainly not before further clarification of the need for such a market and consideration of alternative designs.

LSA recommends some next steps for this review that could help lay the groundwork for a revived discussion of capacity markets.

First, the CAISO should explore the results of the 33% RPS modeling simulations for energy revenues and to infer ancillary service and capacity revenues (as well as for the need for operational attributes) for different classes of resources, perhaps with some additional modeling sensitivities to account for different hydro years, different gas prices, etc. This analysis could provide further insight into the distribution of future generator revenues among energy, ancillary services and capacity by 2020, as well as sensitivity to different system conditions and resource mixes.

Second, the CAISO and the MSC should review the status of the east coast ISO/RTO CCMs, in light of developments since the CAISO's prior benchmarking of their designs. After all, in the prior rounds of CCM discussions, the CFCMA and the CAISO advocated a version of the CAISO-New England FCM, whereas current thinking on the east coast, at least by capacity suppliers, appears to favor PJM's RPM. Despite recent FERC decisions, the future of both those capacity markets could be in jeopardy due to measures taken by state regulators to affect market clearing prices. Moreover, neither of those markets has faced the challenge of a rapid increase in renewable energy production in just 10 years, and as noted by the CAISO, several of the other ISOs/RTOs explicitly rejected including operational attributes in the capacity product. Given that backdrop, the CAISO could provide its own conclusions as to whether, given the experience so far, a CCM should be advanced and what the design should be. The CAISO also has new resources in its MSC to examine these questions concurrently.

These preliminary steps could be completed by 2011 Q3 and presented to stakeholders and State regulators as a prelude to any further discussions.

Forward Reserve market

LSA supports further evaluation of a forward reserve market. Such a market could also help hedge exposure to the more volatile day-ahead and real-time ancillary service prices that will arise at higher levels of renewable integration.

Ancillary services currently account for only about 1-2% of payments to generators (on average). In the CAISO's recent 33% RPS simulations, for the 33% RPS trajectory case, the combination of regulation and load-following capacity requirements being modeled amount to a total of only about 2800 MW in the upwards and downwards directions on average per hour, about double current levels. Moreover, a load-following reserve requirement will be a fraction of the simulated load-following capacity requirement, since some of it will be provided by the inherent load-following capability in the dispatch prior to consideration of the additional supply variability and forecast error. These simulation results may be underestimates, but they indicate that a FRM is not likely to be a full substitute for a capacity payment, since even with higher procurement of reserves, the surplus capacity that will available on the gas fleet could result in continued low ancillary service prices, even in forward time-frames.

LSA recommends that the CAISO provide a further scoping paper on a FRM that explores these issues by end 2011 Q2.

Additional Topics for Road-Map

LSA does not have specific additional topics at this time to add to this already large agenda. We would emphasize again the value of an annual or even sub-annual process for using market simulations to evaluate the timing of integration