**CALIFORNIA ISO**

**RENEWABLE INTEGRATION:**

**MARKET AND PRODUCT REVIEW PHASE 2**

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**COMMENTS OF THE STAFF OF THE**

**CALIFORNIA PUBLIC UTILITIES COMMISSION**

**ON PHASE 2 DISCUSSION & SCOPING PAPER**

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## TABLE OF CONTENTS

## I. INTRODUCTION

The Staff of the California Public Utilities Commission (CPUC Staff) appreciates this opportunity to comment on the California ISO's (CAISO) Discussion & Scoping Paper on Renewable Integration Phase 2 (Scoping Paper) issued on April 5, 2011 and the Stakeholder Discussion on April 12, 2011. The CPUC Staff supports the CAISO's commitment to supporting the integration of renewable resources while maintaining system reliability by seeking stakeholder input on a framework (or roadmap) for market changes to be designed and implemented over the next several years.[1]

The CPUC Staff strongly recommends that the CAISO's first task on a renewable integration roadmap should be to decide what *fundamental* market process reforms it will pursue to accommodate renewable integration, taking into account ongoing WECC-wide initiatives and the Federal Energy Regulatory Commission's (FERC) rulemaking on Variable Energy Resources (VER Rulemaking, Docket No. RM10-11). The fundamental process and operational reforms proposed by the CAISO include a potential 15-minute market in real time and other changes to the basic day-ahead and real-time scheduling, commitment and settlements framework. These changes establish the market framework, and stakeholders must understand that framework in order to evaluate other potential enhancements to market processes and new products for achieving operational flexibility (such as pricing commitment constraints or deploying short term reserves products).

The CPUC Staff therefore recommends that the CAISO place the consideration of specific new market mechanisms for enhancing flexibility later on a renewable integration roadmap. More detailed planning of longer-term reforms should come after stakeholders and the CAISO understand what changes are on the horizon for fundamental market timelines and processes, and have the benefit of additional analytical studies on the expected system needs. The results from the CAISO's 33% Renewable Portfolio Standard (RPS) integration study and other analyses of relevant market data must be available to inform stakeholders' and the CAISO's decisions on longer-term reforms. A longer-term renewable integration roadmap

[1] *See* Scoping Paper, p. 3.

should also support broader state energy programs and priorities and fulfill expected inter-agency coordination.

Finally, while the CPUC Staff supports engaging stakeholders in a discussion of *principles* that should guide cost allocation, it cautions the CAISO against committing to any specific cost recovery methodology or allocation in the early phase of a roadmap. Stakeholder and CAISO decisions about specific cost allocation mechanisms or new market products should *follow* decisions regarding fundamental market processes and ongoing assessments of the amount and costs of flexibility needs. The fundamental market reforms and assessment of flexibility needs developed through the 33% integration study should inform any analyses of the potential feasibility and efficacy of specific candidate reform measures to reduce total system needs and costs.

## II. ESTABLISHING A ROADMAP WITH SPECIFIC MARKET REFORMS FOR RENEWABLE INTEGRATION IS PREMATURE UNTIL AFTER THE CAISO DECIDES ON FUNDAMENTAL MARKET REFORMS

The first tasks on the CAISO's renewable integration roadmap should include (1) establishing fundamental market reforms, (2) completing updated integration analyses and other market assessments, and (3) discussing with stakeholders which additional market reforms should be prioritized based on the state's energy goals.

### A. Deciding on Fundamental Changes to Day-Ahead and Real-Time Market Processes should be the First Task on a Renewable Integration Roadmap.

The CPUC Staff urges the CAISO to make the first task on a roadmap be establishing fundamental changes to Day-Ahead and Real-Time market processes and timelines that will facilitate renewable integration and be consistent with the FERC's VER Rulemaking. Establishing a 15-minute market in real time, a full hour-ahead market, or integrating the Residual Unit Commitment (RUC) process into the Integrated Forward Market (IFM) would each change the fundamental framework of CAISO's market processes and timelines. The outcome of FERC's Rulemaking on VERs should also affect decisions on such fundamental market changes, as the FERC appears to be moving towards requiring transmission providers to accommodate intra-hourly scheduling potentially in 15-minute intervals.[2] The CAISO is also already working on a pilot project to implement half-hourly schedules and dynamic scheduling across the interties. If the stakeholders do not first understand what *fundamental* market design changes the CAISO expects to make in response to these factors, they cannot make informed and efficient decisions about what other individual reform measures to pursue.

More specifically, the CAISO has identified as "market enhancements" three types of changes that it would be better to characterize as *fundamental* process reforms. These potential modifications, and any other proposed fundamental changes, should be debated and decided as the first task on a renewable integration roadmap—before the CAISO adopts a more detailed roadmap for other process reforms and new products. The potential reforms that the CPUC Staff recommends categorizing as fundamental changes include:

***15-Minute Market in Real Time.***

Moving to a 15-minute market in real-time should be given serious consideration as a desirable fundamental reform. This should provide greater flexibility and accuracy for scheduling, commitment, and market participants' bidding and use of forecasts. It may benefit renewable generators that rely on forecasts and operational decisions that improve closer to real time; it should also benefit the overall market. Moving to 15-minute markets should reduce the need to procure load-following resources outside of the energy market through potentially complex commitment constraints or using a new load-following product.

The CAISO's evaluation of a 15-minute market should take into consideration WECC-wide reforms and the federal regulatory landscape. A 15-minute market in real time may be consistent, and better integrated, with a WECC-wide movement to intra-hourly scheduling. It could also be useful—or even necessary—for meeting requirements that may emerge from the FERC's VER integration rulemaking process.

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[2] The CPUC Staff understands that the FERC's ongoing rulemaking regarding VERs integration is in progress but that it may take some time before a final rule is implemented. The CPUC is not suggesting that the CAISO must wait until the FERC issues a final rule before it moves forward with identifying market reforms to assist in renewable integration. Nevertheless, the CAISO should use the current proposed rulemaking for guidance and explain to stakeholders what fundamental market process reforms it believes may be necessary to accommodate intra-hourly scheduling as viewed by the FERC.

***Full Hour-Ahead Market.***

A second potential fundamental process reform the Scoping Paper presents is introduction of an hour-ahead market with full settlements. The CPUC Staff presently agrees with the CAISO that the effort and complexity of implementing a full hour-ahead market is unlikely to be justified by the benefits of a full hour-ahead market.[3] The CPUC Staff recommends considering such a major reform only if the demonstrated benefits (for example, if it would improve opportunities for load participation, or improve renewable generation scheduling and risk management) outweigh the disadvantages.

***Changes to the Residual Unit Commitment Process.***

The Scoping Paper also categorizes potential changes to the Residual Unit Commitment (RUC) process as one of the potential "enhancements to existing market design." The CPUC Staff disagrees that this should be treated as a simple "enhancement," especially if the RUC is integrated with the Integrated Forward Market (IFM) as suggested in the Scoping Paper. Rather, this should be categorized as a fundamental market process change within the overall day-ahead and real-time market frameworks and timelines. Accordingly, questions about the RUC (especially its closer linkage to the IFM) should be considered as part of the first task for Phase 2 before the CAISO develops a longer-term roadmap and or evaluates more specialized measures such as priced constraints or new products.

The CPUC Staff has several concerns regarding potential impacts of integrating RUC into the IFM. While better factoring of forecast uncertainties and projected ramping needs into day-ahead scheduling and commitment decisions and optimization should be valuable for renewable integration, the advantages or disadvantages of integrating the RUC into the IFM must be more fully analyzed and vetted with stakeholders, including:

- Would adding constraints to day-ahead scheduling and unit commitment hinder more efficient and flexible market-based solutions for market participants seeking to manage their integration cost exposure, or to provide flexibility services?
- Would integrating the RUC into the IFM (or otherwise expanding the optimization functions of RUC with IFM) enhance or hinder opportunities

[3] *See* Scoping Paper, p. 16.

for participation by nonconventional resources to provide flexibility, such as load participation, demand response, storage, and VER controls?

- How would integrating RUC into the IFM affect energy and ancillary service prices? For example, virtual bids impact Locational Marginal Prices in the day-ahead market, and the investor owned utilities are not currently required to bid any minimum percentage of their forecasted load into the Day-Ahead market but the RUC clears at a price that meets the CAISO Forecast of CAISO Demand, and therefore prices may be altered by greater integration of IFM and RUC.

### B. The CAISO Should Make Updating Integration Study Results and Other Relevant Market Analyses a Near-Term Priority for a Roadmap.

Stakeholders need relevant (and vetted) empirical and analytic information before they weigh in on whether particular proposed reforms are economically and operationally justified and efficiently targeted. Such studies must be available before the CAISO decides to institute major new market mechanisms such as products or priced constraints.

In addition to the CAISO's 33% integration studies, valuable information will come from market data on the effectiveness of current and potential measures supporting flexibility, including data on the System Ramping Constraint (SRC)[4] that is about to be deployed on an interim basis, anticipated market changes to the bid floor/ceiling, and the final proposal to modify the Participating Intermittent Resources Program (PIRP). Market evaluations should also be informed by analysis of the potential contribution of out-of-state resources to variability and flexibility, taking into account the prospect of more frequent scheduling on interties.

Above all, the CPUC Staff emphasizes the importance of the CAISO's reporting and discussing with stakeholders the results from its updated round of 33% integration studies *before* it commits to specific major integration measures or a detailed roadmap. The CAISO is now producing initial results on system regulation and load-following needs, as well as a wider range of implications for the electric system, under resource portfolios and other assumptions consistent with the CPUC's Long Term Procurement Planning (LTPP) process.[5] The CPUC Staff commends the CAISO for its efforts to complete modeling of these scenarios, which are

[4] The CPUC Staff refers to "Flexible Ramping Constraints" interchangeably with "System Ramping Constraints".

[5] See preliminary results posted at www.caiso.com/23bb/23bbc01d7bd0.html.

critical to the CPUC's resource planning in the LTPP. Before the CAISO and stakeholders dive into crafting specialized market reforms or a detailed roadmap, the CAISO needs to synthesize its 33% integration study results in a report and vet them with stakeholders. Stakeholders will need to understand the results as they relate to expected operational requirements and generation fleet capability that will be needed to support California's statutorily-mandated 33% RPS under a realistic range of future conditions. This information should play a critical role in the selection of market reforms.

Finally, as the CAISO provides the results of updated integration studies and market information, it should not ignore potential flexibility sources beyond conventional fossil and hydro resources. Demand Response, expanded and advanced storage, and enhanced controls for renewable generators could each contribute to a market-based or portfolio approach for managing variability. These measures are only beginning to surface in the market, and have not yet been significantly addressed in the CAISO's integration studies. Examining such measures should receive sufficient resources and priority placement on a roadmap, so that the CAISO can develop market reforms that support—and not inhibit—these alternative resources.

### C. Understanding what Inter-Agency Coordination is Necessary to Ensure Consistency with the State's Energy Priorities and the CPUC's LTPP Would Help Stakeholders Define a Longer-Term Roadmap.

Before it fills in the longer-term tasks for a renewable integration roadmap, the CAISO should identify and discuss with stakeholders what market design reforms should be prioritized based on their implications for achieving the state's energy priorities and expected inter-agency and inter-balancing area authority coordination, as well as the CAISO's own existing catalogue of market design initiatives.

Any roadmap the CAISO adopts should be consistent with the energy priorities and mandates set by Governor Brown and the California Legislature. For example, Governor Brown has set targets for developing new distributed generation and recently signed the 33% renewable portfolio standard that limits the amount of imported renewable generation that is eligible to satisfy RPS targets. The CAISO should identify for stakeholders what market reforms it believes may need to be prioritized in order to support these energy priorities as an early task on a renewable integration roadmap. At a minimum, the CAISO must ensure that any design reforms pursued as a result of the Phase 2 initiative are consistent with achieving the State's articulated energy priorities.

The CAISO should also expressly address linkages between proposed market reforms and other critical programs and interagency coordination, including the CPUC's LTPP, Resource Adequacy, and Renewable Procurement Standard (RPS) proceedings, and measures that the CAISO is committed to under the ongoing California Clean Energy Future (CCEF) initiative. The CCEF explains dependencies and highlights, among other things, the extensive inter-agency coordination between the CAISO, CPUC, and other state agencies on integration and related issues. For example, the CCEF articulates dependencies relating to Once Through Cooling planning and renewable integration modeling in a way that helps to ensure compliance with reliability and environmental goals while minimizing costs borne by ratepayers. The CCEF articulates the interaction in future LTPP cycles between CAISO and CPUC integration study efforts, particularly regarding distributed generation, transmission planning and curtailment practices.

Finally, as part of this task, the CAISO should consider how potential renewable integration market reform priorities relate to critical near-term action items in the existing CAISO Revised Catalogue of Market Design Initiatives.[6] Integrating renewable generation is embedded in the CAISO's *overall* market, system and planning activities and requires interactions and coordination with other market initiatives, as well as other state energy agencies. The CAISO should therefore expressly consider and explain to stakeholders how a renewable integration roadmap would fit with the existing catalogue.

## III. COMMENTS ON SPECIFIC MARKET REFORMS AND PRODUCTS DISCUSSED IN THE SCOPING PAPER

### A. Market Process Reforms That May Be Suitable for Near-Term Implementation.

The CPUC Staff supports evaluating following four proposed market process reforms below for near-term implementation as "no regrets" market reforms:

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[6] *See* Revised Catalogue of Market Design Initiatives, October 18, 2010, available at http://www.caiso.com/280d/280de3ee50bd0.html.

***Hourly contingency-only election for operating reserves*.**

Giving operating reserves the choice to bid as contingent versus non-contingent status on an hourly basis appears to be a worthwhile refinement to the existing market design that could increase flexibility for market participants and the potential supply of reserves for managing variable generation. This measure could be pursued as a near-term, no-regrets change, unless stakeholders or the CAISO demonstrate significant disadvantages or potential unintended consequences.

***Multi-settlement system for ancillary services*.**

This appears to be a useful market modification that can increase system flexibility and should be considered for near-term implementation. The CAISO should present stakeholders with additional information on the applicability to, and potential implications for, a net load-following (ramping or balancing) reserve product.

***Uneconomic adjustment priority for VERS.***

When non-economic curtailment is needed, the CAISO should consider applying an uneconomic adjustment priority to VERS because this is consistent with the state's energy loading order. However, reliability requirements must be satisfied and the potential unintended consequences of this reform should be adequately assessed before implementing this measure.

***Pay for performance regulation/FERC's frequency regulation proposals*.**

The CPUC generally supports the FERC's proposal of performance payment to Frequency Regulation Services.[7] The CPUC Staff is also interested in the potential benefits that may be provided by the analogous proposal presented by PJM staff at a recent CAISO meeting. The CAISO has also developed the Regulation Energy Management proposal to address similar issues, which may affect participation by storage resources. The CPUC Staff understands that some CAISO staff members have identified engineering concerns regarding the REM proposal. The CPUC staff encourages the CAISO to review the REM to see if it should be modified in

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[7] *See* Commission-approved Memorandum Authorizing Staff to File Comments on the FERC's Proposed Rulemaking on Frequency Regulation Compensation in the Organized Wholesale Power Markets (Docket No. RM11-7, AD10-11)April 7, 2011, available at http://docs.cpuc.ca.gov/PUBLISHED/REPORT/133611.htm.

light of the more recent FERC proposal, and to consider whether the PJM proposal may add value to such efforts.

### B. Other Potential Reforms and Products that and Should Not Be Prioritized for Near-Term Implementation.

The CPUC Staff does not support considering the following for near-term implementation:

***<u>Long-Term Deployment and Pricing of Ramping Constraints</u>.*** The CPUC Staff understands that the CAISO has identified daily ramping of load and supply as a challenge (in addition to more extreme episodic ramping). Addressing this challenge appears to warrant a priority position within the CAISO's market development planning process. However, using extensive constraints to obtain flexibility through administrative process would add complexity to, and reduce transparency of, the markets. This in turn could inhibit other flexible and more efficient market-based solutions.

The CAISO should analyze the tradeoffs between using a constraints-based approach, rather than a more market-based approach, to achieve ramping and load-following flexibility. The analysis should be informed by empirical information and analysis including: results from the deployment of the System Ramping Constraint (SRC), results from the CAISO's 33% RPS integration study, a consideration of how load-following needs will be met through incremental and decremental energy bids after the revised bid ceiling and floor are implemented (assuming increased participation by renewable generators in scheduling and bidding), and an assessment of the likely impacts of the final proposed modifications to PIRP. If these assessments show that the system will require significant additional load-following capacity then the CAISO and stakeholders evaluate whether to pursue a constraint-based or market product-based approach. But deployment and pricing of flexible ramping constraints is not a "near term least regrets" measure, and is not yet ready for inclusion in a detailed roadmap.

***<u>New Short Term Operating Reserve Product – Load-following.</u>***

The CAISO discusses a potential new "load-following reserve" product to provide capability for balancing and ramping within the hour. The CPUC Staff agrees that the CAISO should consider this type of new product. This product would really be a *net* load-following product (load net of renewable generation), and it may provide a flexible market-based alternative for obtaining any needed system flexibility without relying heavily on constraint-based approaches. But a decision on this tradeoff should come *after* the CAISO and stakeholders agree on the direction of fundamental market process reforms and have more data to inform the discussion of whether to create this new product.

Further, in addition to assessing the potential for a new product to add flexibility of choice for market participants as well as market efficiency and transparency, the CAISO must consider:

- How robust and liquid would any market for a load-following product be, and how might it overlap with a more liquid future market for incremental and decremental energy bids?
- How could a load-following product include and support the participation of non-conventional resources for flexibility, such as demand response/participating load, and storage technologies?
- Is a new product desirable if studies demonstrate that significant load-following reserve procurement will likely be needed only in limited periods or episodes when flexibility supply is challenged?
- What implications would creating such a new product have on the long-term bilateral procurement of flexibility services or capacity overall?

Creating a new load-following reserve product is not a near-term, “least regrets measure” and should be evaluated after reforms to the most fundamental Day-Ahead and Real-Time processes and quantification of system operational needs have been clarified. Creating a new load-following product would have significant implications for how costs might be recovered by flexibility providers and allocated to “consumers” of flexibility, and for resource planning and procurement. The impacts also need to be evaluated and discussed in close coordination with the CPUC before the CAISO decides whether and how to design a new load-following product.

***Forward Capacity Market***.

The CPUC Staff would oppose an effort by the CAISO to create a multi-year forward central capacity market (CCM) at this time. The CPUC's LTPP proceeding remains the appropriate mechanism for addressing long term resource planning and adequacy issues, including how to ensure the new development of non-generic capacity types and resources in "the right quantities and the right locations."[8] In particular, creating a centralized procurement mechanism for generic capacity might result in inefficient market outcomes if there is a long-

[8] *See* Scoping Paper, p. 18.

term shift in emphasis to non-peak load driven procurement. Rather than embarking on an effort to define new capacity products and develop a CCM, the CAISO should focus its resources on completing integration studies that the CPUC can use to set contracting requirements for targeted, non-generic capacity with the performance characteristics needed to help integrate renewable resources into grid operations.

The CPUC Staff urges the CAISO to address new non-generic capacity needs within the state's long term planning efforts at the CPUC and before other appropriate state agencies, rather than diverting its resources to creating a CCM.

***Forward (Long-Term) Market Products for Specific Kinds of Operating Reserves***.

The Scoping Paper discusses a potential forward reserve market focusing on forward procurement of specific, defined reserve services. The CPUC Staff believes that while this option should not necessarily be ruled out for the future, it is premature to pursue it until after the CAISO defines fundamental market process changes and specific mechanisms to provide additional reserve services. An important consideration is also whether forward procurement of individual reserve services would produce sufficiently robust markets for those individual reserves, or a sufficiently versatile mix of capabilities to meet uncertain, and potentially volatile, conditions. Further, the CPUC's Resource Adequacy program is the appropriate mechanism for procuring specific reserves that are required to be available to the market to assure reliable grid operations. Any forward markets for individual reserve services would have direct implications for long-term resource procurement and for resource adequacy, and should be assessed in close coordination with the CPUC, especially regarding the LTPP and RA programs.

## IV. PRINCIPLES TO GUIDE DECISIONS ON COST ALLOCATION

The CPUC Staff supports the CAISO's efforts to engage stakeholders early in a discussion of *principles* that should guide cost allocation but cautions the CAISO against committing to specific cost allocation or recovery *measures* at this early stage of Phase 2. Deciding on specific market mechanisms for cost allocation should be a *later task on a renewable integration roadmap that follows* decisions on fundamental market reforms and the other tasks identified in Section I above. The CPUC Staff recommends, however, the following objectives and principles should guide consideration of renewable integration cost allocation.

### A. Creating Incentives for Efficient Behavior does not Automatically Mean that Integration Costs Should be Allocated Directly to Renewable Generators.

One principle that should guide an evaluation of cost causation is to look broadly, including at forces outside of the CAISO markets, at what factors contribute to integration costs besides the actions of renewable generators themselves. The Scoping Paper states that "[a]n overarching question to keep in mind throughout this topic is how the market rules – particularly with regard to allocation of integration costs – can be used to provide long-term incentives for developers of VER to design new renewable resources that are better able to manage their own variability."[9] The CAISO appears to assume that integration costs should necessarily be allocated directly to renewable (VER) generators to reduce costs. Instead, stakeholders and the CAISO should examine a broader range of players and decisions that affect integration costs, and therefore a variety of potential ways to structure incentives to reduce integration costs.

Many actors contribute to integration costs and could be incentivized to help manage costs. Renewable developers contribute to integration costs through their choices regarding fuel supply, location, and facility design, and allocating integration costs directly to the developers can influence these choices. But load serving entities (LSEs), including investor owned utilities, contribute to integration costs through their selection of resources and contract terms to meet their RPS and other requirements. Scheduling Coordinators, which may be VER developers, LSEs, or other entities, contribute to integration costs through their operational and scheduling choices. The question of who bears the financial consequences of the various decisions that impact integration costs depends not only on CAISO market processes and settlement rules, but also bilateral contracts, including renewable power purchase agreements that are reviewed and approved by the CPUC. The newly-proposed reforms to the Participating Intermittent Resources Program could also create different incentives for different renewable generators. At the policy level, California's ambitious renewable procurement mandates along with renewable energy credit and tax incentive policies give various entities strong incentives to *maximize* VER generation, which under some conditions can increase the potential for integration costs.

In short, the incremental integration cost that could potentially be attributed to any individual renewable generator depends on complex and interacting decisions and motivations of

[9] Scoping Paper, p. 15.

multiple players. Procurement, contracting, and operations practices do not synchronize perfectly with market settlement rules. Before the CAISO makes decisions on cost allocation it is critical to evaluate how such measures might influence each of these practices and how costs would flow to LSEs and ultimately to consumers.

### B. The CAISO Should Seek to Minimize Costs Ultimately Borne by Consumers by Allocating Integration Costs to the Entities who can best Manage Them.

Consumers (ratepayers) will ultimately pay for incremental system costs caused by renewable integration, and a critical guiding principle for Phase 2 should be to minimize total integration costs borne by them. This requires assessing the likely total integration costs that could result from alternative market reform and cost allocation schemes. The resulting proposed cost allocation solutions may be different than if the CAISO focuses narrowly on linking particular costs to the variability characteristics of specific renewable generators.

In evaluating how to reduce total integration costs, the CAISO and stakeholders should explore the following issues:

- Which market participants can best bear, manage, and thus reduce total integration costs, while achieving the operational benefits the CAISO seeks? Total integration costs depend not only on what integration *measures* can help reduce integration costs, but also on the ability of those to whom costs are allocated to manage *cost risks*. Efficient risk management is an important part of managing total costs and depends on allocating costs to those who can best manage them, which may not be individual renewable generators.
- How do particular cost allocation schemes impact the environment for financing and developing VERs needed to meet the state's energy goals? If generators have limited ability to manage integration cost and risks allocated to them, this could lead to higher renewable contract prices, hinder financing for good projects, or overly conservative operating practices.
- How would cost allocation impact procurement and bilateral contracting practices that are submitted to the CPUC? When addressing *total* costs and cost risk management, the CAISO should closely coordinate with the CPUC and specifically its LTPP and RPS procurement processes. Cost allocation decisions can have implications for the development and procurement of desirable portfolios of both renewable and flexible resources, including demand response and storage.
- How can LSE's or the CAISO most efficiently leverage portfolios to flexibly manage cost risks for renewable integration, and who has access to those portfolios?

### C. Additional Information on Expected Costs and Fundamental Revisions to CAISO Market Design Must Inform Cost Causation Allocation Decisions.

A third important principle to guide cost causation decisions is that these important decisions should be informed by analyses that will be available in the near-term. These analyses will shed light on operational needs, and thus the magnitude and types of costs that will arise, as renewable generation's market share grows. While it is timely to begin considering principles and potential mechanisms for allocating costs for integrating renewable resources, other Phase 2 efforts must precede decisions on how to allocate integration costs through specific market rules and processes. Making good cost allocation decisions depends on first establishing what kinds and sources of integration costs are anticipated and what mechanisms will be available to manage them. This in turn depends on understanding what reforms to the fundamental framework of market processes and timelines the CAISO expects to deploy, in order to determine what mechanisms for enhancing flexibility (such as constraints or new products) could be deployed within that framework.

Accordingly, the CAISO must vet, and provide stakeholders sufficient opportunities to evaluate and understand, analytic results and market information that will clarify flexibility needs and their potential costs. Any decisions regarding cost allocation mechanisms must be preceded by adequate assessment of how much flexibility the CAISO expects to need beyond business as usual operations of the energy and ancillary services markets, taking into account already approved reforms and system changes. Stakeholders must have access to additional information from the CAISO's 33% integration studies, assessments of market information from interim deployment of the SRC, and changes to the PIRP and bid floor/ceiling.

Cost allocation decisions must take into account any allocation principles, requirements or criteria that are required as a result of the FERC's rulemaking on VERs integration. For example, the FERC may require that the costs of regulation capacity reservation be charged to buyers of VERs output, not to VERs themselves, and may establish guidelines for justifying differential cost allocation to different market participants.

### D. Cost Causation cannot be Measured Directly and will Require Administrative Approximation and Judgment.

Assigning the costs of procuring or reserving flexible capacity for "integration" purposes can only be based on an approximation of who or what causes additional regulation, load-following or other integration needs.  Behavior of renewable generation (or loads) in a given interval does not cause the CAISO to commit flexible reserves for that interval, because the commitment is based on *expected* variability and error (actual output relative to forecasts or schedules) looking *ahead* to the interval.  This expectation may be based on historical statistics, analyses and modeling, and will likely be modified based on actual market conditions as the interval draws near.

Because of the administrative approximation and judgment inherent in measuring integration cost causation, key cost allocation questions that should guide this initiative, in addition to the five Scoping Memo questions, include:

- How and with what accuracy can or should expected variability/error be assigned to any particular variable or renewable resource?
- How can or should the procurement of reserves be related to a particular variable or renewable resource's expected or actual variability error for particular intervals?
- How should cost allocation take into account operating and scheduling behavior, as opposed to variability and error that is caused by physical characteristics of renewable generators?
- How can costs allocated to those causing flexibility needs ("flexibility consumers") be linked to how flexibility providers are actually compensated, avoiding excessive or opportunistic compensation?
- What methodology should be used to justify allocation of costs, and how should the CAISO determine what is the appropriate level of accuracy needed to justify cost allocation decisions?
- How should system context and its uncertainty (such as composition of the system-wide resource portfolio) impact how cost responsibility is assigned to individual market participants?
- What are the consequences of relying on constraints-based or other administrative "solutions" versus more market-based approaches, and should market-based considerations have any role in determining the *amount* of flexibility needed?

Further, because there is significant uncertainty about the magnitude and responsibility for integration costs, any cost allocation methods or principles should be applied conservatively (low cost allocation)—at least until better information and operational data are available.  Cost allocation decisions today are based on expected, but uncertain, system and market conditions that are several years away.  The limited accuracy of analyzing cost allocation based on categories of variable and renewable resources or estimated similarity among them also dictates taking a cautious approach until more experience and information becomes available. The CAISO should proceed cautiously, recognizing that load will *ultimately* pay for integration costs, and considering that operating reserve costs are currently allocated to load in a manner that does not reflect cost causation.

Finally, the CAISO should ensure that it shares operations and cost allocation information with LSEs, SCs, renewable generators, regulators and other stakeholders to enable them to better understand of what factors are driving integration costs and their allocation. This supports not only cost management but also assessment of the fairness and efficacy of cost allocation. If the CAISO decides to allocate costs based on generic resource categories, it should also provide methods to refine allocations as additional information and analysis become available.

### E. Generation Interconnection Procedures should not be Used as a First or Primary Method to Allocate Integration Costs.

The CPUC staff does not recommend allocating integration costs through the generation interconnection procedures (GIP) unless and until the CAISO determines that this can produce constructive and fair results, and alternative cost allocation mechanisms are inadequate. Allocating costs through the GIP would target VERs to bear integration costs without any regard for how they are subsequently operated or whether they contract to provide their own integration services or provide other sources of flexibility. It also gives no regard to how GIP-assigned integration costs might flow to LSEs and ultimately to consumers, and whether that process would result in an efficient cost management. Using the GIP to allocate integration costs would likely provide little incentive to efficiently manage the contracting and operation of a renewable project or to provide flexibility. As a minimum starting point, if the CAISO intents to pursue GIP-based allocation of integration costs, it should specifically explain and discuss with stakeholders how costs might be appropriately allocated in this manner, and how this would incentivize efficient behavior and minimize total integration costs.