Review of Reliability Must Run and Capacity Procurement Mechanism

Straw Proposal

June 26, 2018

Market & Infrastructure Policy

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1. Executive Summary

The California Independent System Operator Corporation ("ISO") is reviewing and considering improvements to its existing backstop procurement mechanisms - the capacity procurement mechanism ("CPM") and Reliability Must-Run ("RMR") agreement - in light of recent experiences implementing RMR agreements and CPM designations and to address concerns identified by the ISO as well as stakeholders about the increased use of backstop procurement by the ISO. This initiative will review the RMR tariff provisions, pro forma agreement and procurement processes, and seek to clarify and align the use of RMR procurement and backstop procurement under the CPM tariff. The scope of this initiative is shown in Figure 1 below.

Figure 1 – Scope of this Initiative

RMR and CPM

- Provide notification to stakeholders when a resource informs ISO it is retiring
- Clarify when RMR procurement is used versus CPM procurement
- Explore whether Risk of Retirement ("ROR") CPM and RMR procurement can be merged into one procurement mechanism

RMR

- Develop interim pro forma RMR agreement, i.e., change termination and re-designation provisions
- Update certain terms of pro forma RMR agreement
- Update allowed rate of return on capital for RMR compensation
- Make RMR resources subject to a must offer obligation ("MOO")
- Make RMR resources subject to the Resource Adequacy Availability Incentive Mechanism ("RAAIM")
- Consider whether Condition 1 and 2 options are needed for RMR
- Ensure RMR designation authority includes system and flexible needs
- Allocate flexible RA credits from RMR designations
- Streamline and automate RMR settlement process
- Lower banking costs associated with RMR invoicing

CPM

- Evaluate year-ahead CPM local collective deficiency procurement cost allocation to address load migration
- Evaluate if load serving entities ("LSEs") are using CPM for their primary capacity procurement

The major features of the ISO's straw proposal are summarized below.

1. The ISO will provide notification to stakeholders when a resource informs the ISO that it is planning to retire, mothball or otherwise make the entire resource unavailable.
2. The ISO describes when the RMR procurement process is used versus the CPM procurement process.
3. The ISO proposes to continue to have the authority to issue both CPM and RMR designations.
4. All CPM and RMR resources will have a MOO.

5. All CPM and RMR resources will be subject to RAAIM.
6. To address the concern with a resource that is at ROR being able to seek RMR compensation instead of ROR CPM compensation, the ISO will delete from the CPM tariff the existing authority to designate a resource needed for year two with a bridge in year one. The ISO will add that same authority to the ISO's RMR tariff to allow the ISO to designate a resource as RMR that is needed for years two or three with an appropriate length bridge.
7. To address the concern with CPM compensation – where resources are currently allowed to file at FERC for compensation above the CPM soft offer cap price using the Schedule F cost of service methodology currently in the RMR agreement and keep market revenues earned – the ISO will change the methodology to an approach where the resource can file at the Federal Energy Regulatory Commission ("FERC") for compensation based on the going-forward fixed costs ("GFFCs") of its resource using the same cost categories and the same 20% cost adder used for the CPM reference unit and the resource can keep market revenues earned.
8. The ISO will revise the RMR pro forma agreement so that the default arrangement will be a cost of service agreement with a MOO where the resource will have its cost of service paid and any market revenues earned above its cost of service will be credited against monthly fixed costs. At the ISO's discretion, and in limited circumstances when appropriate, the resource owner may negotiate an RMR agreement where the resource is not paid all of its cost of service and may keep market revenues earned above cost of service.
9. The ISO will clarify its authority under the RMR tariff to include that the ISO can designate a resource for system or flexible needs, which will be in addition to the ISO's existing RMR authority to designate for local needs and to meet Applicable Reliability Criteria.
10. In order to be offered an RMR designation, a resource must file a letter with the ISO, consistent with the requirements in its Participating Generator Agreement ("PGA"), wherein the resource states that it is planning to retire at a certain date. The ISO will expect the resource to also send a retirement letter to the California Public Utilities Commission ("CPUC") indicating the same intention.
11. The ISO proposes revisions to several elements of the pro forma RMR agreement to update it to current aspects of the ISO market.
12. The ISO will update the allowed rate of return on capital that is currently in the RMR pro forma agreement.
13. The ISO proposes to allocate flexible RA credits from RMR designations.
14. The ISO proposes to leverage the current settlement system and interface to automate the RMR validation and invoicing processes.

15. The ISO proposes to lower banking costs associated with RMR invoicing by establishing one bank trust account for all payments from and disbursements to RMR parties.
16. The ISO proposes to keep the current year-ahead CPM local collective deficiency procurement cost allocation methodology as it believes that the issue of load migration has largely been addressed by the CPUC's June 2018 RA Decision for the 2019 RA compliance year.

The ISO plans to take to the ISO Board of Governors in July 2018 for approval a non-substantive, limited interim change to the pro forma RMR agreement that would allow the ISO to terminate the RMR agreement and immediately re-designate RMR resources under the new substantive RMR agreement that will be developed under this initiative once that new pro forma agreement is accepted by FERC. The interim pro forma agreement provisions would be in effect for new RMR designations and agreements once this change is accepted by FERC (expected around October/November 2018). The interim pro forma agreement provisions would not apply to RMR resources that are under the RMR agreements that are currently in effect, or RMR designations made prior to FERC accepting the interim pro forma agreement.

The ISO plans to take its proposal for all of the other enhancements in this initiative (the items other than the "interim pro forma RMR agreement" item discussed above) to the ISO Board of Governors for approval in March 2019. The goal is for the enhancements to be in effect for the 2020 calendar year.

A list of acronyms and abbreviations used in this straw proposal is provided in Appendix 1.

2. Plan for Stakeholder Engagement

The schedule for this initiative is shown in Table 1 below.

Table 1 – Schedule for this Initiative

Stage	Date	Milestone
Milestones prior to May 30	Nov 2, 2017	ISO commits to undertake review of RMR and CPM
	Jan 2, 2018	Issue market notice announcing this initiative
	Jan 23	Post issue paper and straw proposal for two items
	Jan 30	Hold stakeholder meeting
	Feb 20	Stakeholder written comments due
	Mar 13	Post draft final proposal for two items
	Mar 20	Hold stakeholder meeting
	Apr 10	Stakeholder written comments due
Straw proposal	May 30	Hold working group meeting
	Jun 26	Post straw proposal
	Jul 11	Hold stakeholder meeting

Stage	Date	Milestone
	Aug 7	Stakeholder written comments due
Revised straw proposal	Aug 27	Hold working group meeting
	Sep 19	Post revised straw proposal
	Sep 27	Hold stakeholder meeting
	Oct 23	Stakeholder written comments due
Second revised straw proposal	Nov 1	Hold working group meeting
	Nov 19	Post second revised straw proposal
	Nov 26	Hold stakeholder meeting
	Dec 21	Stakeholder written comments due
Draft final proposal	Jan 23, 2019	Post draft final proposal
	Jan 30	Hold stakeholder meeting
	Feb 22	Stakeholder written comments due
Final proposal	Mar	Present proposal to Board of Governors

3. Decisional Classification

For this initiative, the ISO will seek approval from only the Board of Governors. The ISO believes this initiative falls outside of the scope of the Energy Imbalance Market ("EIM") Governing Body's primary and advisory roles because the initiative does not seek changes to either rules of the real-time market or generally applicable rules of all markets. Rather, the initiative seeks modifications to the ISO's backstop capacity procurement authority to ensure that reliability requirements are met in the ISO's balancing authority area. These proposed changes will not apply to EIM balancing authority areas. The ISO seeks stakeholder feedback on this EIM classification of the initiative.

4. Introduction

The ISO is modifying its approach for this initiative based on FERC's April 12, 2018, order in Docket Number ER18-641. In that order, FERC rejected the ISO's January 12, 2018 filing to enhance the process for ROR CPM designations. One of the key features of the ROR CPM proposal was to create a new window each spring, in addition to the existing window each fall, for resources to request a ROR CPM designation. In its order FERC found that a spring window could result in front-running the RA process, price distortions and interference with bilateral RA procurement. In its order FERC noted that the ISO had initiated a stakeholder process to review RMR and CPM issues and strongly encouraged the ISO and stakeholders to adopt a holistic, rather than piecemeal, approach and encouraged the ISO to propose a package of comprehensive reforms.

This initiative will consider changes to the RMR and CPM paradigms. The ISO also is actively engaged at the CPUC in advocating improvements to the RA program. The ISO believes that through its efforts in this initiative and its efforts at the CPUC the ISO is reviewing holistically the most important aspects of procurement to ensure reliable operation of the grid.

<u>RMR Authority</u> - Since the startup of the ISO in 1998 the ISO has had authority through RMR designations/agreements to procure essential reliability services from resources. There were a considerable number of RMR resources in the early years of ISO operations. In 2005, the RA program was established to reduce RMR procurement and to cost-effectively secure capacity to meet the reliability needs of the grid. In 2006 the RA program was augmented to include local RA capacity requirements. These forward capacity procurement mechanisms significantly reduced the need for RMR resources. Between 2010 and 2016 there were just a handful of RMR resources under contract as the vast majority of the system's reliability needs were met through RA procurement. Recently there has been an uptick in the number of resources under RMR due to policies and emerging trends in the energy industry that are fundamentally altering the resource procurement and RA landscape. Since RMR use had been declining for years, the ISO had not seen an urgent need to update the RMR provisions and structure. However, with the recent increased use of RMR, and the potential for more RMR as traditional gas-fired resources are under risk of retirement pressures, the ISO believes RMR should be updated to reflect current conditions. As part of the November 2, 2017 approval by the Board of Governors of an RMR designation for the Metcalf Energy Center, ISO management committed to commence a stakeholder initiative in early 2018 to look at the RMR framework process as well as potential modifications to RMR regarding Condition 1 and Condition 2 designations.

<u>CPM Authority</u> - Since 2006, the ISO has had backstop procurement authority to meet specific reliability needs. Currently the ISO has authority to procure resources under its CPM tariff to ensure the reliable operation of the grid under the following situations: (1) there is insufficient RA capacity (system, local, flexible) in year-ahead and/or month-ahead RA showings; (2) there is a collective deficiency of local capacity resources; (3) a "Significant Event" occurs on the grid; (4) the ISO "Exceptional Dispatches" non-RA capacity; or (5) capacity is at risk of retirement that is needed for reliability in a future year. The ISO has updated the CPM several times since implementing it, most recently in November 2017 when the Board of Governors approved, and the ISO subsequently filed at FERC, enhancements to the ROR CPM process. During the November Board meeting, the ISO committed to examine the relationship between RMR and CPM procurement and explore whether they can be better aligned or consolidated.

<u>RA Program</u> - The ISO believes that the Resource Adequacy ("RA") program should be improved to align with the operational needs of the transforming grid. An improved RA program could reduce the potential use of ISO backstop procurement. The ISO is actively participating in the CPUC's RA proceedings and is advocating several important changes to the RA program. Some of the topics that the ISO is advocating at the CPUC are listed below.

- Enhance flexible RA capacity procurement requirements.
- Establish multi-year RA procurement.

- Improve load forecasting.
- Establish Local Capacity Area-specific procurement, including down to the local sub-area.
- Improve counting rules to align resource capabilities with operational needs.
- Establish a methodology to assess LSE RA showings to ensure that ISO operational needs are met.
- Move up the annual RA showing timeline to enable timely and informed retirement decisions.

As discussed with stakeholders during the May 30, 2018 working group meeting, a formal settlement approach may be needed to reach agreement on changes to RMR and CPM. The RMR construct took years to develop and was heavily litigated given the complexity of the issues and the trade-offs that ultimately had to be agreed to. The CPM tariff was developed through settlement discussions, as parties were so far apart in their views that a traditional ISO stakeholder process could not achieve a proposal. It may not be efficient to develop changes to RMR and CPM using the traditional, iterative stakeholder process. The ISO is interested in hearing from stakeholders on whether they see value in using a settlement type approach now or possibly in the future for some or all of the topics in this initiative.

5. Stakeholder Comments

This section provides a summary of the written stakeholder comments that were received on the March 13, 2018 ISO paper. The full version of the written stakeholder comments that were received is provided in Appendix 1.

1. Comments on proposal to make RMR resources subject to a MOO.

Calpine does not support the imposition of a MOO on Condition 2 resources, but does not object to a MOO on Condition 1 resources as it is consistent with the market incentives inherent in Condition 1. Calpine believes that consideration of imposing a MOO on Condition 2 units should be deferred to a later phase of this initiative once more is known about the RA reforms.

CLECA supports making RMR resources subject to a MOO. CLECA is concerned that use of the current penalties for non-performance in the RMR agreement is insufficient and recommends the ISO further consider other performance incentives in phase 2.

DMM supports a MOO for all RMR resources.

IEP opposes making RMR resources subject to a MOO in the absence of a more thorough assessment by the Department of Market Monitoring (“DMM”) and the ISO of the potential impact of such change on the ISO’s markets and market-clearing-prices.

NRG does not support making RMR units subject to an RA-like MOO. The fundamental problem to be solved is the failure of the RA program. The ISO should suspend this initiative and allow all parties to focus their efforts at RA reform in Track 2 of the CPUC’s RA proceeding. The ISO should take up this initiative only after the CPUC has finished Track 2 of the RA proceeding.

ORA supports adding a MOO to future RMR contracts but has concerns with the proposed language regarding energy bid calculations. Major maintenance adders ("MMAs") should not be included in the energy bid price, and should be removed. If ISO instead chooses to keep MMAs in the proposal, a description of RMR- specific MMAs is required.

PG&E supports inclusion of a MOO. The ISO should provide additional details to describe how it will implement the use plan that identifies and preserves the specific hours for RMR dispatch operation while requiring market participation during other periods. The ISO should impose the Non-performance penalty, which includes the fixed revenue requirement and any capital expenditures, for a unit's failure to meet the MOO. The ISO's proposal should not include MMAs in ISO generated cost-based bids for RMR dispatches.

SCE supports a MOO but believes the MOO is not sufficient. The ISO proposal should have the same non-performance penalties on RMR resources that it does on RA resources. Scheduling Coordinators ("SCs") for RMR resources should be required to bid $0 in the Residual Unit Commitment ("RUC") market, failing which the ISO should insert a bid in RUC at $0 on behalf of the RMR resource.

Sierra Club supports making RMR units subject to a MOO. RMR contractual costs already account for cost of service, which include maintenance, so it is unclear why an SC should be able to include a MMA. The ISO should clarify or remove this term.

Six Cities strongly support application of a MOO for RMR Condition 1 and 2 resources.

2. Comments on proposal for ISO to provide notification to stakeholders that a resource is planning to retire.

Calpine does not object to disclosure of resources that are seeking an evaluation of the reliability-based need for that resource. NRG asserts that notice of "retirement" is too narrow and should include all forms of unavailability permitted under the tariff. We also support a market participation notification when the reliability analysis is completed.

CLECA, PG&E, SCE, Sierra Club and Six Cities support this item.

NRG does not object to this item.

ORA requests that ISO provide the information through market notices and modify its proposal to also include the actual owner's notification letter.

Sierra Club askes that the proposal define a timeline for notifying stakeholders and make the written notice available to stakeholders.

3. Comments on potential phase 2 items.

<u>Clarify when RMR and CPM are used.</u>

CLECA believes that greater clarity is needed as to when and under what circumstances RMR versus CPM is utilized to determine what capital costs are recovered under each contract type.

DMM strongly encourages addressing that the CPM is voluntary and can be declined by suppliers with local market power.

NRG believes that if Phase 2 proceeds it should focus on creating a single ISO backstop mechanism.

ORA supports continued refinement of ROR CPM and RMR processes to ensure market participants do not choose between the two to obtain financial incentives which may increase ratepayer costs.

Sierra Club believes the priority for Phase 2 should be to define the purpose and interrelationship of each mechanism.

Six Cities support a comprehensive review of the CPM and RMR with an objective of clarifying and rationalizing the processes.

Combining ROR CPM and RMR.

Calpine supports the proposal if the ISO is suggesting that ROR CPM and RMR designations be combined with RMR.

NRG believes the ISO should have used ROR CPM rather than RMR provisions to keep the Metcalf resource in operation.

Whether to continue to have Condition 1 and 2

Calpine sees no need eliminate either Condition 1 or Condition 2 at this point.

ORA recommends an analysis of the costs and benefits of RMR Conditions 1 and 2 and whether they are both necessary to ensure reliability.

Expansion of authority to backstop

Calpine does not object to a clarification of the ISO's authority to manage reliability, including, as necessary the acquisition of attributes (such as flexibility) necessary to manage reliability.

CLECA believes that it is unnecessary to expand authority to use RMR or CPM for flexibility need and renewable integration because it is not a local capacity requirement nor is it necessary for renewable integration.

ORA believes the ISO has not demonstrated why it seeks to expand its authority given current mechanisms in place to procure flexible capacity.

Six Cities recommend that the ISO either describe the topic with greater clarity and specificity or delete the topic from the list of items under consideration for Phase 2 of the initiative.

RMR compensation

DMM believes that compensating a resource based on its full sunk capital costs (after depreciation) is unjust and unreasonable. DMM believes the CPM and RMR provisions can and should be modified based on the key market design principle that resources with market power should be mitigated based on going forward fixed cost.

PG&E proposed that the ISO use going forward cost as the basis for both ROR CPM and RMR.

Aligning the CPM and RMR recovery of capital cost or capital additions

CLECA objects to aligning the CPM and RMR recovery of capital cost or capital additions.

Review the rate of return in CPM and RMR

While Calpine does not object to an evaluation of the pre-tax rate of return built into the tariff, Calpine believes there are much higher reform priorities and this should be deferred.

CLECA believes the rate of return values for RMR or CPM should be the same and be updated as the cost of capital changes.

Six Cities attach high priority to reviewing the allowed rate of return on capital for RMR and CPM compensation as the allowance currently in place is outdated and excessive.

Allow for capital additions

Calpine believes that as energy margins decline, it will be increasingly necessary to consider mechanisms to recover the costs of incremental capital. No rational business will invest incremental capital (for maintenance, flexibility or improvements) without a clear path to collect a return of (in the form of depreciation), and a return on (in the form of carrying costs, debt/equity) that investment. The ISO's backstop mechanism, whether RMR or a modified CPM, must include provisions to ensure that incremental capital earns a reasonable return.

Simplify RMR invoicing/settlement

Calpine is a passionate advocate of RMR settlement simplification, but urges rational caution and reasonable expenditures on reform.

Load migration

CLECA believes the ISO should work with the CPUC to develop a schedule or other mechanism that could avoid a collective deficiency and appropriately address the cost allocation for such a deficiency in the context of load migration.

Joint CAA believe the ISO should work with the CPUC on Local RAR improvements.

NRG believes if Phase 2 proceeds it should focus on addressing the load migration issue for annual CPM designations.

ORA believes the ISO should quickly explore tariff and non-tariff modifying approaches to address this issue to provide equitable cost allocation for LSEs experiencing load shifts.

PG&E believes the ISO should address the load migration issues associated with annual CPM calls.

SCE believes the cost allocation for load migration item should be moved forward and addressed in phase 1.

Flexible RA credits

Calpine supports the proposal to reduce the overall demand for flexible capacity as a result of RMR contracting.

CLECA believes to the extent the RMR and CPM resources provide flexible capacity, their effective flexible capacity should be part of the MOO and count against the flexible capacity requirement allocated to LSEs.

NRG believes that this issue is a timing matter and can be addressed on its own.

ORA supports the allocation of flexible RA value for RMR resources and believes it should be addressed in phase 1.

PG&E believes the ISO's proposal should account for all the RA characteristics associated with the RMR capacity and facilitate the counting of these RA attributes by allowing the capacity to be allocated directly to LSEs.

SCE believes that all resource attributes relevant to RA should be accounted for and credited to the customers that are paying for these resources.

Sierra Club believes that RMR contracts should include the allocation of flexible RA capacity and the proposal should be amended to specifically include allocation of Flexible RA.

<u>Evaluate if LSEs are using CPM as a primary means for capacity procurement.</u>

NRG strongly believes that the RMR and CPM procurement at the end of 2017 was not the result of LSEs or suppliers suddenly deciding that they now prefer these two mechanisms over RA contracts, but, in significant part, of limits placed on LSE contracting by CPUC decisions and the failure of the RA program to ensure needed resources receive RA contracts. Consequently, this effort should have the lowest priority.

4. Other Comments

<u>Scope of initiative</u>

CLECA believes that the issue of allocation of RMR or CPM when the local need spans across TAC areas, such as LA Basin and San Diego, should be included in this initiative.

ORA has expressed concerns that the current RMR process leaves no time for consideration of alternative solutions and instead provides generators with information about their market position.

PG&E proposes inclusion in scope of changes to the TPP and LCR study process to identify needs earlier: PG&E also proposes removing the ISO's discretion whether or not to CPM for a collective deficiency.

<u>Change RA process timeline</u>

DMM strongly encourages the ISO to address timeline of the RA program and the CPM process should be moved back to accommodate the actual timeline needed to make decisions about resource retirements and potential alternatives for meeting local needs.

6. Changes from March 13, 2018 Paper

The ISO lists below the major changes that have been made from the March 13, 2018 paper to create this straw proposal.

- The ISO has clarified how MMAs and opportunity costs would be used in RMR bids.
- The ISO has clarified when RMR procurement is used versus CPM procurement.
- The ISO has merged ROR CPM and RMR into one procurement mechanism.
- The ISO has changed the CPM pricing formula for resources that file at FERC for a CPM price above the CPM soft-offer cap price.
- The ISO has clarified how it will treat Condition 1 and Condition 2 options for RMR resources.
- The ISO proposes that RMR resources will be subject to RAAIM.
- The ISO has identified several pro forma RMR agreement terms that should be updated to reflect the current ISO market.
- The ISO has added a filing at FERC this summer for an interim RMR pro forma agreement that would allow the ISO to terminate the RMR agreement and immediately re-designate RMR resources under the new substantive RMR agreement once it is accepted by FERC.

7. Straw Proposal

This section presents the ISO's straw proposal, which includes items suggested by both the ISO and stakeholders. The items are divided into the following categories: RMR and CPM items (items that are common to or have an overlap between RMR and CPM), RMR items (items specific only to RMR tariff provisions, pro forma agreement or procurement processes), and CPM items (items specific only to the CPM tariff).

7.1 RMR and CPM Items

7.1.1 Provide notification to stakeholders when a resource informs ISO it is retiring

Early in this initiative several stakeholders requested additional transparency when the ISO receives a notification from a resource owner that its resource may retire and there is a potential that the ISO may procure the resource under the ISO's backstop authority to ensure reliable operation of the grid. The ISO agreed that this information is something that the ISO should share with stakeholders in a timely manner and included this item to the scope of this initiative.

The ISO is in the process of implementing a new policy where the ISO will now notify stakeholders when it receives a notice that a resource plans to retire, mothball or otherwise make the entire resource unavailable to the ISO long-term. The new policy is being implemented through a change to Generator Management Business Practice Manual ("BPM"). The ISO expects the new policy to be implemented by July 1, when the BPM change management process is completed. The new policy establishes if resource owner sends such a notice the information will not be considered confidential. For more information on this item, see PRR 1056.[1]

7.1.2 Use of RMR and CPM Backstop Procurement

In this section the ISO discusses several of the scope items in combination to provide a comprehensive discussion of the ISO's proposed use of RMR and CPM procurement authority. It must be noted that the ISO has existing authority from FERC to do the majority of the things discussed in this section, and the ISO is not proposing wholesale changes to the overall RMR and CPM construct as the ISO believes that as a whole these two existing procurement mechanisms work well and function as was intended. In this section the ISO provides some changes to some of the features of RMR and CPM and will discuss its vision for how these mechanisms work in both this straw proposal and in person during the July 11 stakeholder meeting. The items that are covered in this section are listed below.

- Clarify when RMR procurement is used versus CPM procurement - Some stakeholders believe that the ISO should provide additional detail on the use of RMR procurement versus use of CPM procurement. The ISO agrees that additional information would be helpful and will provide it in this initiative. The ISO will consider the process interplay between RMR and CPM to ensure that the interplay between the mechanisms works properly. The ISO will provide a process map showing how retirement requests will be evaluated within the overall process. The goal is to provide an understanding of how the procurement processes interact with each other.
- Explore whether ROR CPM and RMR can be merged into one mechanism - The ISO will explore with stakeholders whether it is possible to integrate RMR and ROR CPM into a single, cohesive ISO procurement mechanism (or merge certain aspects of each) where the ISO would assess the two different reliability need horizons, the upcoming year or "year one" and the year after that year or "year two" under a single procurement mechanism.
- Change the CPM pricing formula used for resources that file at FERC for a CPM price above the CPM soft-offer cap price - Compensation for CPM resources whose costs exceed the CPM soft offer cap and who desire compensation above the CPM soft offer cap is tied to the formula for determining cost of service compensation for RMR units in Schedule F of Appendix G of the ISO tariff. Several stakeholders have stated that they believe cost of service pricing for CPM resources is inappropriate and have suggested that the ISO pay GFFCs and not cost of service for CPM procurement.
- Consider whether Condition 1 and 2 options are needed for RMR resources - When RMR was initially established it made sense to offer resource owners an option (Condition 1) where the owner could be paid for some of its fixed costs

[1] At http://http://www.caiso.com/Documents/Presentation-BusinessPracticeManualChangeManagementMay222018.pdf

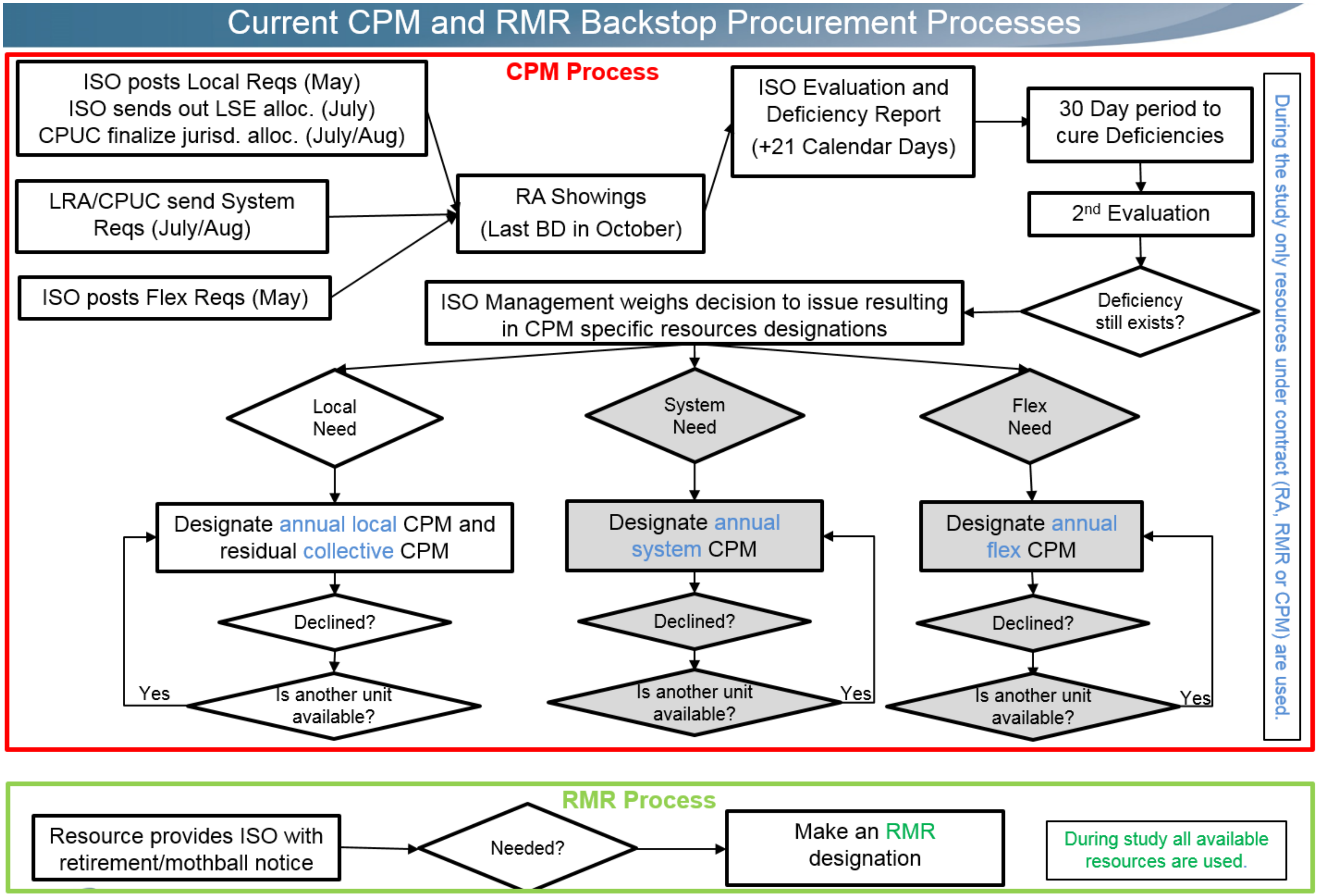
and also earn market revenues that it could keep, or an option (Condition 2) where the owner could be paid for all of its fixed and variable costs and in return would forfeit any market revenues it earned. Today, it appears the greater uncertainty around earning sufficient market revenues is causing RMR resource owners to generally choose the Condition 2 option to ensure they can recover their costs. The ISO would like to explore with stakeholders whether there is a need going forward to continue to have both options available.

- <u>Ensure RMR designation authority includes system and flexible needs</u> - The ISO will ensure that the ISO's authority to designate RMR resources includes system and flexible reliability needs, which would be in addition to procuring for local reliability needs.

Provided below in Figure 2 is a map of the designation processes for RMR and CPM. The ISO discussed this map with stakeholders during the May 30, 2018 working group meeting. During the working group meeting the ISO explained that one of the key takeaways from the map is that there currently is a gap if all resources that are offered a CPM designation for system or flexible needs decline the designation. For local needs the ISO can turn to an RMR designation if all resources that are offered the CPM designation decline, but this may not currently be clear for system and flexible reliability needs. Therefore, the ISO believes that its RMR designation authority should be clarified to include system and flexible reliability needs.[2]

[2] ISO tariff Section 41.3 provides, "In addition to the Local Capacity Technical Study under 40.3.1, the CAISO may perform additional technical studies, as necessary, to ensure compliance with Reliability Criteria. The CAISO will then determine which Generating Units it requires to continue to be Reliability Must-Run Units, which Generating Units it no longer requires to be Reliability Must-Run Units and which Generating Units it requires to become the subject of a Reliability Must-Run Contract which had not previously been so contracted to the CAISO." which clearly includes any need required to satisfy Applicable Reliability Criteria,"

Figure 2 – ISO Backstop Procurement Processes



The ISO's straw proposal for RMR and CPM procurement is summarized below. The key elements of the straw proposal are presented in bullet form to aid the reader in seeing how the features align with one another.

CPM and RMR

1. The ISO will continue to have the authority to issue both CPM and RMR designations.
2. All CPM and RMR resources will have a MOO.
3. All CPM and RMR resources will be subject to RAAIM.

CPM

4. To address the concern with the CPM compensation methodology where resources are currently allowed to file at FERC for compensation under a CPM designation above the CPM soft offer cap price using the Schedule F cost of service methodology that is in the RMR agreement and keep market revenues earned, the ISO will change the CPM compensation methodology to an approach where the resource can file at FERC for compensation based on the GFFCs of its unit using the same cost categories (i.e., *ad valorem* costs, insurance and fixed operation and maintenance costs) and same cost adder (20% adder) that are used for the CPM reference unit and keep market revenues earned. The 20% adder will provide incentives or revenue sufficiency for resources to perform long-term maintenance or make improvements that may be necessary to satisfy new environmental requirements or address reliability needs associated with renewable resource integration.
5. To address the concern with a resource that is at ROR being able to seek RMR compensation instead of ROR CPM compensation under a CPM designation, the ISO will delete from the CPM tariff the existing authority to designate a resource needed for "year two" with a bridge in year one. The ISO will add that same authority to the ISO's RMR tariff to allow the ISO to designate a resource as RMR that is needed for years two or three with an appropriate length bridge.
6. If a resource declines a CPM designation, the ISO will not go directly to offering the resource an RMR designation. The ISO will inform the resource that if the resource wants to consider an RMR designation, the resource must submit a retirement letter. If the resource does not wish to submit a retirement letter, then the ISO will assume that the resource will continue to be available for dispatch (as it has not indicated an intent to retire) and if needed subsequently for a reliability need the ISO may offer the resource an Exceptionally Dispatch to meet the immediate reliability need.

RMR

7. The compensation paid to an RMR resource will be based on its cost of service, which will include an allowed rate of return on capital based on net plant and capital additions costs which can include major maintenance expenses.

8. The ISO will update the allowed rate of return on capital that is currently in the RMR pro forma agreement.
9. The ISO will clarify authority under the RMR tariff to include the ISO can designate a resource for system or flexible needs, which will be in addition to the ISO's existing RMR authority to designate for local needs and to meet Applicable Reliability Criteria. The ISO proposes that Section 4.1 of the RMR pro forma agreement be revised to: 1) remove the current limitation to only dispatch RMR resources for local reliability and non-competitive congestion, and 2) add provisions allowing the ISO to dispatch RMR resources for local, system and flexibility needs of the ISO market. Under the current ISO market construct, energy and Ancillary Service ("AS") bids are co-optimized in the Day-Ahead Market ("DAM") and Real-Time Market ("RTM"). Moreover, the ISO needs tools to address any type of reliability need in the ISO market to maintain efficient grid operations, and not just limited to local reliability. With increasing renewable penetration and a growing trend of gas resources retiring, the ISO finds an increasing need for such services in the market. RMR resources are a viable tool to meet these needs provided that the current limitations in the pro-forma RMR agreement are removed. The current RMR pro forma agreement provisions prevent the ISO from dispatching RMR resources for system reliability and flexible capacity reasons, while market needs are increasing in frequency and impact.
10. The ISO will add authority under the RMR tariff so that the ISO can designate a resource needed for "year two" or "year three" with a bridge of appropriate length. This authority in the RMR tariff will replace the ROR CPM authority the ISO currently has in the CPM tariff.
11. The ISO will update the RMR pro forma agreement so that the default RMR pro forma agreement will be a cost of service contract with a MOO where the resource will have its cost of service paid and any market revenues earned above its cost of service will be credited against monthly fixed costs. At the ISO's discretion, and in limited circumstances when appropriate, the resource owner may negotiate an RMR agreement where the resource is not paid all of its cost of service and may keep market revenues earned above its cost of service.
12. In order to be offered an RMR designation, a resource must file a letter with the ISO, consistent with the requirements in its PGA, wherein the resource states that it is planning to retire at a certain date. The ISO will expect the resource to also send a retirement letter to the CPUC indicating the same intention.

The key elements of the ISO's straw proposal are summarized in Table 2 and Table 3 below. These two tables highlight the proposed changes from the existing paradigm.

Table 2 – Overview of CPM

Type of Designation	Voluntary or Mandatory[3]	Type of Compensation	Components of Compensation	Notes on Compensation
System monthly	Voluntary	1. As bid into auction 2. Soft offer cap price of $75.68/kW-year 3. Can file at FERC for compensation above soft offer cap price (FERC approves compensation)	1. "Safe harbor" price at or below soft offer cap price 2. $75.68/kW-year price is based on GFFC of reference unit 3. ~~Can file for cost of service compensation per RMR Schedule F~~ and also keep market revenues	For 3., change methodology so resource has to file at FERC for compensation based on GFFCs of its unit using same cost categories and same cost adder as was used for reference unit (no longer will be able to use RMR Schedule F). Plus resource keeps market revenues.
System annual	Voluntary	Same as above	Same as above	Same as above
Local monthly	Voluntary	Same as above	Same as above	Same as above
Local annual	Voluntary	Same as above	Same as above	Same as above
Local collective deficiency	Voluntary	Same as above	Same as above	Same as above
Cumulative flexible monthly	Voluntary	Same as above	Same as above	Same as above
Cumulative flexible annual	Voluntary	Same as above	Same as above	Same as above
Significant event	Voluntary	Same as above	Same as above	Same as above
Exceptional dispatch	Voluntary	Same as above	Same as above	Same as above
~~Risk of retirement~~	~~Voluntary~~	~~1. Soft offer cap~~ ~~2. Can file at FERC for compensation above soft~~	~~1. GFFC of reference unit ($75.68/kW-year)~~	Delete this type of CPM ROR designation from CPM tariff and expand RMR tariff

[3] A CPM designation is voluntary if the resource has not bid into the CPM auction. If the resource has bid into the CPM auction, then the CPM designation is mandatory.

Type of Designation	Voluntary or Mandatory[3]	Type of Compensation	Components of Compensation	Notes on Compensation
		~~offer cap price (FERC approves)~~	~~2. Can file for cost of service compensation per RMR Schedule F and also keep market revenues~~	authority to backstop for "out years" needs.

Table 3 – Overview of RMR

Type of Designation	Voluntary or Mandatory	Type of Compensation	Components of Compensation	Notes
Local, system, flexible ISO can designate for needs in year one, year two or year three	Mandatory	Cost of service	Base arrangement offered will be cost of service and claw back all market revenues, and resource, if it desires to take on risk, can negotiate arrangement where resource is not paid all of its cost of service and can participate in market and keep market revenues earned	Clarifying RMR authority to ensure ability to designate for system and flexible needs Adding RMR authority to designate for needs in years two or three to provide an appropriate bridge to year of need

The ISO will update the RMR pro forma agreement so that the default RMR agreement will be a cost of service agreement where the resource will have its cost of service paid and any market revenues earned above its cost of service will be clawed back. The cost components for RMR agreements are described in Schedule F of Appendix G of the ISO tariff and include the following categories:

- Operating expenses; and
- Return on net investment.

Through the ISO's proposed compensation methodology resources will be:

- Eligible to recover fixed costs;

- Eligible to recover variable costs while providing services to the market;
- Required to bid at cost based rates, plus any MMA costs (for startups of variable energy) and any opportunity costs rates;
- Eligible for bid cost recovery; and
- Subject to “claw back” for any market revenues earned above its cost of service.

Because RMR designations are mandatory and generally only designated when a resource is exiting the market or becoming unavailable to the market for an extended period, the associated compensation will allow a resource to cover all of the costs incurred with remaining in service while needed, but will not incorporate any additional market revenues. Any market revenue above cost of service bids will be “clawed back” from the resource receiving the designation and resources will be allowed to keep any revenues return on their variable costs that they incur while providing market services. Additionally, resources will be eligible for bid cost recovery payments when market revenues are insufficient to cover incurred variable costs, and will continue to receive reimbursement for actual costs incurred while performing maintenance during the term of the RMR contract. Generally compensation will cover all of a resource’s costs to operate, and will be aligned with the current compensation offered to Condition 2 RMR resources.

7.2 RMR Items

7.2.1 Develop interim pro forma RMR agreement, i.e., change termination and re-designation provisions

The ISO plans to take to the ISO Board of Governors in July 2018 a non-substantive, limited interim change to the pro forma RMR agreement that would allow the ISO to terminate the RMR agreement and immediately re-designate RMR resources under the new substantive RMR agreement once it is accepted by FERC (following the end of the RMR contract year). The right to immediately re-designate would not apply to RMR resources under RMR agreements currently in effect. Under the current RMR agreement, the ISO cannot terminate and immediately re-designate a resource for RMR service, but must wait for a one year period before it can re-designate the resource. It would be imprudent for the ISO not to extend the RMR contract under these circumstances. The proposed interim RMR contract would apply to RMR designations following FERC acceptance of a new pro forma RMR contract.

The current RMR agreement allows ISO to extend the term of agreement by giving notice no later than October 1 (section 2.1(b)) and limits the ISO’s right to re-designate an RMR resource in the event the ISO terminates or does not extend the RMR agreement. The ISO may not designated during the one year period following termination (section 2.2(d)), except under limited circumstances. The ISO proposes to create an interim modification to the pro forma RMR agreement where the ISO would to have the right to terminate the RMR agreement once FERC accepts the new pro forma RMR agreement and the ISO would have the right to re-designate the RMR resource (and other resources at the same facility) under the new pro forma agreement. This item is being undertaken by the ISO in parallel with this straw proposal. A draft of the interim pro forma RMR agreement was posted to the ISO's website on June 12, 2018 and stakeholder written comments are due by June 25, 2018. The ISO will hold a stakeholder call on July 10, 2018 to discuss the draft of the interim pro forma RMR agreement. The ISO plans to seek approval to file the interim pro forma RMR agreement at FERC at the July 25-26, 2018 Board meeting.

7.2.2 Update certain terms of pro forma RMR agreement

The ISO proposes several revisions to the pro forma RMR agreement and these revisions are discussed below.

- <u>Remove Ancillary Service bid insufficiency test completely and revise the dispatch provisions to align with current market paradigm</u> - The original pro forma RMR agreement contained several limitations on the ISO ability to dispatch RMR units and these limitations were designed when there was no market power mitigation and no capacity procurement requirement. These limitations remain in the current form of the RMR pro forma and include dispatch for non-competitive congestion, and dispatch for AS only after a bid insufficiency criteria has been met. Under the current ISO market construct, the RA obligations have been designed to ensure there is sufficient capacity bidding into the market where energy and AS bids are co-optimized in the DAM and RTM. Further, the ISO may commit additional capacity in the DAM to meet bid insufficiency conditions under Tariff section 31.5.4. With these mechanisms in place, the bid insufficiency limitation designed in the RMR agreement serves no purpose; therefore, these limitations may be lifted to allow for more efficient use of the resource by dispatching it to serve reliability needs, whenever the market is unable to meet those needs. Also, even with current co-optimization of energy and AS bids, the ISO still has the issue of being able to address inter-hour AS needs in the RTM. This gap can be filled by increasing ISO's flexibility to dispatch for AS beyond "bid insufficiency", since such situations arise in spite of sufficient bids in DAM. Additionally, applying RA type MOO for energy and AS resources to RMR resources, makes the bid insufficiency test anachronistic.
- <u>Update pro forma RMR agreement Schedule M and Schedule C to include Greenhouse Gas ("GHG") compliance cost calculation, DAM and RTM gas price index, and updated Scheduling Coordinator (SC) charge calculation, update Schedule M to be consistent with ISO tariff and BPM rules on bidding, and seek input on defining a heat rate curve formula in Schedule C for multi-stage generator resources</u> - Schedule C and Schedule M of the current RMR pro- forma agreement contain a few archaic provisions such as antiquated gas price indices, an out-of-date fixed scheduling coordinator charge, and no provisions to reflect GHG compliance cost. The RMR pro forma agreement also needs updates to accommodate the multi-stage generator resource model. The ISO currently has well defined tariff provisions and BPM sections for calculating the GHG cost adder for bids, DAM and RTM gas price indices, resource heat rate curves, and GMC based scheduling coordinator charges. The ISO recently included tariff and BPM defined forms of some of these concepts in the FERC filed RMR agreements for Metcalf Energy

Center, LLC and Gilroy Energy Center, LLC, with definitive support from all parties. The ISO believes that while this does not affect the purpose or scope of the RMR agreement it helps improve efficient operation and administration of RMR units.

- Possible Additional terms - The ISO continues to review the pro forma RMR agreement to identify other areas of improvement and will raise it with stakeholders as the ISO progresses through the initiative.

7.2.3 Update allowed rate of return on capital for RMR compensation

Cost-based compensation for RMR resources includes a rate of return on capital, which is currently 12.25%.[4] The 12.25% number is "hard wired" (specifically stated) in the tariff many years ago when RMR was first implemented and has not been updated to reflect current financial market conditions or rate cases. The ISO proposes to update the number as it may not be accurate for today's conditions. Options to address this item include hard wiring a new number or establishing a reference to a source where the number could be periodically changed without tariff changes or amendments to the RMR pro forma agreement.

The current ISO tariff specifies a 12.25% rate of return applied to net investment, with the capacity for the rate to adjust – in the upward direction only –based on United States Treasury bond price changes between the effective settlement date and the first informational filing. In practice this rate is relatively static at the 12.25% floor specified in the tariff. The ISO seeks to revise the rate of return to better align with current market conditions and current industry rates of return and to allow the rate to adjust as business conditions change in the future. There are a variety of solutions that the ISO is considering as an update to these provisions. These potential solutions include:

1. Leave the current tariff language in place;
2. Determine a base rate that is allowed to float – up or down – according to the United States Treasury bond return rate, (or on some other public measure of return);
3. Have an independent expert construct a rate of return that is updated periodically (i.e. every 4-5 years like CPM soft offer cap pricing);
4. Require market participants to propose a rate of return, accompanied by independent validation, during negotiations for each RMR designation;
5. Use a blended rate of returns from recent transmission rate cases from the IOUs, with an adder for potential additional risk; and
6. Determine a specified methodology to calculate a rate of return that would be completed and updated by the ISO every other year. FERC and the investor owned utilities ("IOUs") have documented methodologies to complete such calculations.

[4] The compensation for an RMR agreement is outlined in Schedule F of the Pro Forma RMR contract in the Tariff: http://www.caiso.com/Documents/AppendixG_ProFormaReliabilityMustRunContract_asof_Apr1_2017.pdf.

In 2014 FERC developed a new methodology for computing a return on equity ("ROE") similar calculations used in the natural gas and oil pipeline industry.[5] FERC then applied these rates for New England transmission assets. Through this methodology FERC calculated a zone of reasonableness between 9.39% and 11.74%, with a base return on equity set at the midpoint, or 10.57%. Although this zone does not include the ISO tariff specified floor of 12.25% (a difference of 1.68 percentage points from the base), this range does not take into consideration differences in geography or differences in risk between transmission owners and those who may receive RMR designations.

In May 2018, the owners of the Mystic generating units and the ISO New England reached an agreement, which was filed at FERC, for a cost of service agreement to retain the use of the resources for the New England bulk electricity market.[6] This agreement included a rate of return on equity, in addition to other fixed costs, calculated at 10.26% (or 1.99 percentage points below the 12.25% rate of return in California). This rate was determined by an independent expert using a discounted cash flow analysis model that estimated a range of required returns between 7.33% and 11.59%. This methodology for constructing the range of rates and for selecting the appropriate rate are consistent with other recent FERC precedent.

7.2.4 Make RMR resources subject to a MOO

On March 13, 2018 the ISO posted a draft final proposal to have RMR resources subject to a MOO. Many stakeholders supported the ISO moving forward with its proposal. However, several of the stakeholders that support a MOO requested that the ISO clarify how maintenance costs will be treated in bids given an RMR agreement includes compensation for such costs. Several stakeholders believe the ISO should not file a MOO requirement until the ISO has conducted a thorough discussion with stakeholders of all of the items in the scope of this initiative. In addition, some stakeholders believe that if there is to be a MOO additional resource performance requirements are needed beyond what the ISO has proposed to date, such as making an RMR resource subject to the RAAIM mechanism that RA resources are subject to.

The current construct for the RA program requires that procured resources offer into both the energy and AS markets. The current construct for RMR was developed at ISO startup before the RA program was implemented, and does not require RMR resources to bid into energy and AS markets with a MOO. The DMM submitted a filing to FERC on November 22, 2017 that provides arguments for including a MOO.

> *Under the Reliability Must-Run (RMR) Service Agreement filed in this proceeding, the Metcalf Energy Center ("MEC") would operate under Condition 2 of the CAISO's RMR tariff and contract provisions. As a Condition 2 RMR resource, the Metcalf Energy Center and other units seeking Condition 2 RMR agreements would be withheld from participating in the CAISO markets during many – and possibly most -- hours, even though consumers would be bearing*

[5] https://www.ferc.gov/media/news-releases/2014/2014-2/06-19-14-E-7.asp#.WygckapKiUl.
[6] https://elibrary-backup.ferc.gov/idmws/common/OpenNat.asp?fileID=14920790.

> *the full fixed and variable costs of this capacity. The limits on market participation by Condition 2 units are economically inefficient, distort overall market prices, undermine the CAISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers. To ensure mitigation of local market power and avoid artificial inflation of overall market prices, the limits on market participation by Condition 2 units must be removed and a must offer requirement must be established for all units under both Condition 1 and Condition 2 of the CAISO's RMR tariff and contract provisions.*[7]

In light of these arguments the ISO believes that it is appropriate that resources receiving RMR designations have a MOO for the energy and AS markets.

The ISO proposes that all RMR resources have a MOO for energy and AS, similar to the current RA MOO for energy and AS. The MOO for RMR resources is described below for the two types of compensation that an RMR resource may receive.

- MOO for an RMR Resource that is paid All of its Cost of Service and All Market Revenues earned above its Cost of Service are Clawed Back - The SC for the RMR resource will be required to submit energy and AS cost-based bids during all hours that the resource is physically available.[8] If energy and AS bids are not submitted by the SC, up to full capacity of its RMR contracted amount, the ISO will submit cost-based bids up to RMR capacity, with bids generated in the same way that the ISO generates bids when an RA unit fails to submit bids.[9,10] The ISO generated energy bids will include start-up costs, minimum load costs, and energy costs. The ISO generated AS bids will be priced at $0/MW per hour. Pursuant to existing provisions, the ISO will have the ability to instruct a unit to

[7] See DMM filing at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14762784.

[8] Including costs in Schedule M of the RMR agreement. AS bids can be greater than $0/MW per hour using the formula in Schedule M. The SC can include opportunity costs and major maintenance adders in energy bids, but only if such costs are applied for by the RMR resource in advance and are approved in advance by DMM, which will check to ensure that an RMR resource does not receive double payments. Pursuant to existing provisions, the SC will credit back to the Participating Transmission Owner ("PTO") market revenues earned above the RMR contract cost. Requiring that a resource bid in at actual cost, considering these additional adders, implies efficient commitment and dispatch instruction.

[9] Including energy market costs, which are specified in Schedule M of the pro forma RMR agreement: http://www.caiso.com/Documents/AppendixG_ProFormaReliabilityMustRunContract_asof_Apr1_2017.pdf. However, if the ISO inserts AS bids, the AS bids will be priced at $0/MW per hour like is done for RA capacity. Energy bids will include any applicable major maintenance adders in start-up costs and minimum load costs and any applicable opportunity cost adders. Note that an RMR resource must submit in advance and DMM must approve in advance any major maintenance adders or opportunity cost adders and DMM will have access to the RMR agreements and will not allow double recovery of costs. Bids will be submitted for all AS services that the RMR resource is certified to provide. Pursuant to existing provisions, the SC will credit back to the PTO market revenues above the RMR contract cost.

[10] There will be an obligation in RUC for the full RMR capacity at $0. If the design of RUC changes over time, the ISO will revisit this provision.

not run, such as for a reliability or environmental limitation, or if unit would exceed its contract service limits.

The ISO believes that major maintenance costs (adders) and opportunity costs should be reflected in bids, to ensure that the true cost of unit operation is considered in market decisions. This will result in optimal market decisions. DMM currently reviews and approves all MMA and opportunity costs adders considered in the market. The ISO expects that DMM would approve MMA and opportunity costs as a part of the RMR agreement process.

An RMR resource will be eligible for bid cost recovery payments when market earnings are insufficient to cover costs. However, any market revenues earned in excess of the variable costs to operate the RMR resource, as determined in Schedule M, will be clawed back from the RMR resource. Additionally, this mechanism will prevent double payment to resources for major maintenance and opportunity costs.

- <u>MOO for an RMR Resource that is not paid all of its Cost of Service and can participate in Market and keep All Market Revenues earned above its Cost of Service</u> - The SC for the RMR resource will be required to submit energy and AS <u>market-based</u> bids during all hours that the unit is physically available.[11] If energy and AS bids are not submitted by the SC up to full RMR capacity, the ISO will submit <u>cost-based</u> bids up to RMR capacity as is done for an RMR resource that is paid all of its cost of service and all market revenues above its cost of service are clawed back whose SC does not submit bids up to the full RMR capacity. Pursuant to existing provisions, the ISO will have the ability to instruct a unit to not run, such as for a reliability or environmental limitation, or if unit would exceed its contract service limits.

Specific considerations will need to be made for resources entering into these classifications of RMR agreements regarding major maintenance adders, opportunity costs and bid cost recovery. During these considerations the ISO will follow principles that prevent double payment for major maintenance and opportunity costs.

<u>7.2.5 Make RMR resources subject to RAAIM</u>

Although the current RMR pro forma agreement does include several resource performance incentive provisions, the ISO believes it would be better to make it such that RA, CPM and RMR resources all have the same performance incentive mechanism. RA and CPM resources are currently subject to the RAAIM mechanism, which has non-availability charges for being unavailable relative to a pre-established performance band and availability bonuses payments for availability above the pre-established performance band.

The ISO proposes that all RMR resources be subject to RAAIM and the current RMR resource performance incentive provisions in the RMR pro forma agreement no longer be used to incent performance as RAAIM will be applicable instead. The ISO will determine through the course of

[11] Market bids for an RMR resource receiving this type of compensation are subject to local market power mitigation.

this initiative if any of the current RMR resource performance incentive provisions (see discussion below) stay in RMR pro forma agreement along with the applicability of RAAIM.

The ISO could establish that RMR resources have greater performance obligations than RA or CPM capacity, and this may discourage resources from gravitating toward RMR designations instead of contracting bilaterally for RA or accepting a CPM designation. The ISO is considering having RMR resources only be subject to RAAIM and removing the other RMR performance incentive provisions. The ISO wants to discuss this issue with stakeholders before any decision is made on how many resource performance incentive provisions should be applied to RMR resources.

The current RMR resource performance incentive provisions are contained in Article 8 of Appendix G of the RMR pro forma agreement. The monthly option payments, which are defined in Article 8 of the RMR pro forma agreement, are based on availability and response to dispatches, i.e., the payments are performance based. The paragraphs in Article 8 define the resource performance based payments. There are two primary performance penalty provisions, which are summarized below.

- Under Section 8.5, a financial penalty is calculated for each hour of the penalty period in which the RMR resource is not deemed to be in full compliance with a dispatch notice and is not excused from performance.
- Under Section 8.6, a Long-term Planned Outage financial adjustment will be made if the RMR resource exceeds the historical availability metric established for that RMR contract year.

The text from Article 8 of Appendix G of the RMR pro forma agreement is provided in Appendix 3 to this straw proposal.

Note that the current RMR performance incentives are based on actual resource performance and not bidding behavior as is the case with RAAIM, and any RAAIM charges or payments are not included in the RMR settlement (i.e., the RMR resource gets to keep any incentive payments on top of its RMR settlement or has to pay charges out of its RMR settlement).

7.2.6 Allocate flexible RA credits from RMR designations

CPUC Staff has requested that this item. In its written comments on this initiative CPUC stated: "Staff would also like the current scope of Phase I to include the allocation of flexible RA capacity. The current RMR contracts do not cover the procurement and allocation of flexible capacity. Staff would like to ensure that any future RMR designations include the flexible attributes of the resource. Since ratepayers are paying for all of the costs associated with the operation and dispatch of these resources, they should, be allocated the flexible capacity attributes on the resources. Essentially, the flexible attributes associated with the resource become sunk, if they are not allocated. Staff believes that this would be a small modification, and we request that it be made with the addition of a MOO in the current RMR tariff. To the extent that the ISO cannot address this issue on an expedited basis for Board approval in mid-May, Staff requests that this issue be addressed in Phase 2 of this initiative."

The current pro forma RMR agreement does not cover procurement and allocation of flexible capacity. CPUC staff has asked that RMR designations include the flexible attributes of the RMR resource. The ISO supports this policy. The ISO seeks stakeholder input on any conditions that might need to be established. These conditions might include ensuring that an RMR resource is not counted as providing flexible RA when it does not meet the performance requirements, and the resource owner must agree in the executed RMR agreement that it will fulfill flexible RA operating requirements.

The ISO's initial proposal is to simply take the RMR capacity procured off of the top of the RA flexible requirement.

7.2.7 Streamline and automate RMR settlement process

The RMR invoicing process has remained relatively unchanged since April 2009. Generator transactions and costs are captured on a spreadsheet and submitted to the ISO for invoicing. The RMR invoice amount is based on calculations and validations executed manually outside the existing settlements system and timelines, then subsequently billed through a manual pass-through-bill mechanism. The ISO proposes to leverage the current settlement system and interface to automate the RMR validation and invoicing processes.

The ISO manages invoice cycles for market settlement and separate invoice cycles for RMR settlement, which is prone to delays due to late invoice submittals by the scheduling coordinator. In order for all parties to manage resources more effectively, the ISO proposes to merge the timing of RMR invoicing with the current market settlement timelines. Rather than submit an invoice, the scheduling coordinator would submit revenue and cost requirements in time for RMR invoicing, which would occur at the same time as market invoicing of monthly settlement statements.

The following elements will be considered within the streamline and automate RMR settlement item.

- Standardize RMR invoice submittal timeline – This will include establishing set submittal timelines, aligning the RMR timeline with market settlement invoicing timelines, and aligning the RMR timeline with the settlement dispute timeline.
- Simplify and automate validations – This will include configuring validation equations and publishing validation results to participants.

The ISO will provide a more detailed discussion of this item in the revised straw proposal that is scheduled to be posted on September 19, 2018.

7.2.8 Lower banking costs associated with RMR invoicing

Currently, each RMR agreement requires the establishment of two segregated commercial bank accounts (RMR Owner Facility Trust Account and Responsible Utility Facility Trust Account). These accounts are used to collect charges paid by the responsible utility and disbursed to the RMR owner (and vice-versa). These accounts do not carry any balances as RMR funds are disbursed on the same day as they are received. The current protocol of establishing two accounts does not serve any discernable purpose since all funds are tracked and recorded, regardless of where they are received.

With the recent increase in RMR contracts, the ISO, in its effort to streamline processes and reduce bank fees, would like to change the tariff provisions so that the requirement to open new accounts for each RMR contract are no longer required. In its place, the ISO would propose to establish a bank trust account specific to administering RMR related transactions. Going forward, all payments from and disbursements to RMR parties will be made from this bank account. The advantages to this change are:

- Streamlined process. Since RMR transactions will be processed using one bank account, it will be simpler for both the ISO and the RMR contract parties to administer the processing of payments and disbursements.
- Faster RMR contract implementation. Time and effort are required to open new bank accounts when new RMR contracts are signed. In addition, multi-stage testing is necessary to ensure that these accounts are visible on both the ISO and the RMR contract parties. Under this proposal, testing will be reduced or eliminated (if the RMR contract party has another RMR contract in place).
- Reduced bank fees. The ISO pays a maintenance fee for each bank account that is active. Each account costs $125 per month plus monthly charges for additional services (Wire Transfer, Payment Manager). Thus, less bank accounts to maintain will have both financial and other non-financial benefits (monitoring, reconciliation) as well.

Under any proposal, the possible sections of the ISO tariff that may need to be revised are:

- *11.13.2.1 Facility Trust Account* – References the establishment of the two accounts per contract.
- *41.6 –Reliability Must-Run Charge* – References the payment of RMR invoices to the established accounts.
- *11.29.9.2 CAISO Accounts to be established* – References the establishment and the use of the clearing account.

7.3 CPM Items

7.3.1 Evaluate year-ahead CPM local collective deficiency procurement cost allocation to address load migration

Southern California Edison ("SCE") raised the issue that the ISO might engage in backstop procurement under the CPM, and under certain circumstances, may make local collective CPM designations that the ISO would allocate costs to LSEs on a load ratio share at the time of the procurement (unless the shortfall is attributable to a single LSE). Given the potential for load migration, SCE believes the issue of year-ahead CPM cost allocation to address load migration should be addressed in this initiative. The ISO has included this item as an issue to be discussed, but because of the recent CPUC decision does not believe that any changes will have a significant impact on market results.

Collective year-ahead annual capacity procurement mechanism allocations are made prior to the start of the RA compliance year, generally in December. These procurements are done for a 12-month period, for the RA year. Costs are allocated to each LSE in the Transmission Access Charge ("TAC") area (or areas) where the procurement is made. These costs are allocated to each LSE according to each LSE's respective forecast load share ratio within the TAC area(s) at the ISO coincident peak. The forecast load share ratio is calculated based on values provided to the ISO by the CEC by June 30, and the same forecast is used to allocate individual LCR responsibility in mid-July. RA credit is awarded on the same load share ratio, to each LSE in the TAC area(s), at the same time designations are made and cost allocations are determined.

The primary concern for this issue is allocation of costs for collective capacity procurement mechanism procurements not reflecting actual load share ratios. This occurs when the estimates for load share ratios, based on prior year forecast loads, are significantly different than the actual loads observed in the market. Although load forecasts are carefully constructed, actual loads served by LSEs may differ from forecast loads. This may been true for two reasons. First, actual load may be different than forecasts which cause differences, and second a new LSE may join the market and begin serving a portion of the load that was previously being served by an existing LSE. The second driver, which has had a significant impact in recent years, is the rapid growth of community choice aggregators ("CCAs").

On May 22, 2018 administrative law judges at the CPUC issued a proposed decision adopting local capacity obligations for 2019 and refining the RA program.[12] This decision included treatment of new CCAs in the entire annual RA procurement process, which – if approved - may ameliorate any need for further improvements of cost or credit allocation during the CPM process because of the second issue outlined above. The proposed decision from the CPUC includes the following detail.

> In this proceeding, the proposal of the Commission's Energy Division seeks to ensure that all LSEs participate in all aspects of the year-ahead RA process, including submitting load forecasts and annual year-ahead filings, if they seek to serve load in the following calendar year. Energy Division further recommends that in order for an LSE to expand its territory in the following calendar year, the LSE's year-ahead load forecast and revised load forecast must reflect that expansion. (Energy Division Proposal at 4.)

On December 22 the ISO made year-ahead local CPM designations for 510 MW from the Moss Landing resource located in the Pacific Gas and Electric TAC area, and 545 MW from two Encina resources located in the San Diego Gas and Electric TAC area.[13] For the Moss Landing

[12] This item may be heard by the CPUC as early as June 21, 2018. A copy of the decision is available here:
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M214/K459/214459310.PDF.
[13] http://www.caiso.com/Documents/December222017YearAheadLocalCPMDesignationReport.pdf.

procurement, 490 MW was priced at $6.19/kW-month, while the remaining 20 MW was procured at the $6.31/kW-month soft offer cap for the capacity procurement mechanism. Both Encina resources were procured at the $6.31/kW-month soft-offer cap. The monthly costs for these procurements were allocated in a way consistent with the tariff, where they were first allocated to LSEs within each TAC area with local deficiencies, then to the entire area based on a load ratio share of forecast load.

The ISO believes that the CPUC's June 2018 RA Decision for the 2019 RA compliance year largely mitigates the concern regarding load migration. The ISO prefers maintaining the existing framework for costs and credits as it believes that framework is sufficient for calculating cost and credit allocations going forward. Although a change to the current methodology for allocating costs and credits could be implemented, changes to align costs and credits immediately prior to each RA month would impose a significant cost while offering little benefit once the rules from the CPUC Decision are in place for the 2019 RA year.

While reviewing this issue the ISO considered the several potential options, which are discussed below.

1. Maintain the status quo cost and credit allocations
    - No changes to the existing mechanism for cost and credit allocation for annual collective deficiency capacity procurement mechanism designations. Costs and credits would continue to be allocated according to load forecasts generated by June 30 prior to the start of the RA year, noting that these may include forecasts any new CCAs serving load in the market during the RA year, per the CPUC decision noted above.
2. True up costs and credit allocations prior to each month
    - The ISO could use load forecasts 49 days prior to the start of each month, to determine monthly cost allocations for any collective deficiency CPM procurements. Using this methodology would allow for all RA credit to be available for monthly showings (due 45 days prior to the start of the month) for each of the LSEs. It would not be possible for costs and credit allocations to be trued up for any months where a designation is made within 49 days prior to the month. Because designations are generally not made until mid-December prior to the RA year, this would usually mean that there would be no true up for cost and credit applied to January and February, and these would be treated the same way they are currently treated. Implementation costs for this solution would be particularly burdensome.
3. True up costs after each month (credits may be misaligned)
    - The ISO would use actual load served by each LSE to assess costs for each month for any collective CPM designation made. Because these allocations would be completed after the conclusion of a month, once actual loads are known, there would be no way to allocate credit for LSEs. If costs are allocated

retroactively, there will be a mismatch between monthly RA credit awarded and costs assessed for procurement.

7.3.2 Evaluate if LSEs are using CPM for their primary capacity procurement

The current CPM is the result of a negotiation process conducted among interested stakeholders. That negotiation process concluded with the ISO filing tariff provisions and an additional offer of settlement.[14] The Offer of Settlement included three items "that do not constitute a rate, term, or condition of service provided by the CAISO and that therefore are not addressed in the revised tariff provisions."[15] One of those three additional items was that the ISO would "monitor the use of the CPM to ensure that load serving entities are not relying on the CPM as a primary means of capacity procurement to meet Resource Adequacy obligations . . . ."[16] Specifically, the Offer of Settlement established two triggers that, if met, would result in the ISO opening a "a stakeholder initiative to explore whether load serving entities have relied on the CPM, to an unacceptable extent, as a primary means of capacity procurement."[17] The two triggers were:

- 1) Within a rolling 24-month period, the same load serving entity twice relies on the CPM to meet any Resource Adequacy deficiency (either in an annual or monthly Resource Adequacy plan).
- 2) Any load serving entity meets more than 50 percent of its annual or monthly Resource Adequacy obligation for a year or month, respectively, with CPM Capacity procured by the CAISO on that load serving entity's behalf."

The Offer of Settlement explained that if either trigger were met, then the stakeholder initiative "would consider the CPM designation(s) that triggered the stakeholder initiative and possible solutions to discourage load serving entities from relying on the CPM for forward capacity procurement in the future" and also could "consider prospectively-applicable remedial measures designed to avoid load serving entity reliance on the CPM."

In an order issued on October 1, 2015, FERC accepted the proposed CPM tariff provisions, but noted that the "Offer of Settlement is not a settlement filed pursuant to Rule 602 of the Commission's Rules of Practice and Procedure" and as such would be treated "as record evidence in support of CAISO's section 205 filing."[18]

In its comments on the Issue Paper and Straw Proposal for Phase 1 Items, the CPUC states that the second trigger was met and "therefore it is appropriate to explore all aspects of the CPM tariff including its intended use and its compensation price."[19] NRG and Calpine also view

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[14] *Cal. Indep. Sys. Operator Corp.*, Tariff Amendment and Offer of Settlement, FERC Docket No. ER15-1783 (May 26, 2015) (May 2015 filing).
[15] Offer of Settlement, § 5.1.
[16] Offer of Settlement, § 5.2.
[17] *Id.* [Offer of Settlement, § 5.2.]
[18] *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,001, P 28 n.53 (2015).
[19] CPUC comments, at 10.

the second trigger potentially as being met, but observe that the resulting stakeholder process should be narrower in scope than the scope for which the CPUC advocates.

As noted, FERC did not accept the Offer of Settlement. As such, its terms are not necessarily binding on the ISO or any of the "Supportive Stakeholders" identified in the May 2015 filing.[20] Nevertheless, the ISO will abide by the spirit of the Offer of Settlement, which was that if a LSE appeared to be using the CPM as a means of primary procurement (which is what the two triggers were crafted to capture), then the ISO would hold a stakeholder initiative to consider how it might discourage such behavior.

As a result of the CPMs the ISO issued through the annual competitive solicitation process for the 2018 RA year, some LSEs in the SDG&E TAC area will be credited from the CPM more than half of their local capacity obligation for the SDG&E TAC area. The ISO has concluded that this situation reasonably could be viewed as raising an appearance that those LSE used the CPM for primary procurement.

Based on that conclusion, the ISO intends to consider in this initiative how the circumstances surrounding the year-ahead CPM designations in the SDG&E area could have been prevented had the CPM design included additional remedial measures to discourage LSEs from relying on the backstop for forward capacity procurement. Based on the potential remedial measures identified, the ISO also may consider whether those measures should be adopted prospectively through tariff amendments or other appropriate means.

This item was discussed at the May 30, 2018 stakeholder working group meeting. During the discussion the ISO stated that it believes that the December 22, 2018 CPM designations in the San Diego TAC area were driven by particular circumstances. Specifically, San Diego Gas and Electric was not able to procure the Encina Power Station because of limitations set by the CPUC via Decision 12-04-046.[21] Decision 12-04-046 does "not allow the utility to continue to purchase or receive power generated using noncompliant OTC [once-through cooling facilities] beyond that date [OTC compliance date] even if SWRCB [State Water Resources Control Board] extends the compliance date."[22] In 2017, this provision precluded San Diego Gas and Electric from procuring capacity from the Encina Generating Station despite the fact the SWRCB extended the OTC compliance date. Encina's non-RA status created a year-ahead local RA deficiency in the SDG&E TAC area, which led the ISO to issue an annual CPM designation to two of the Encina units until the under-construction Carlsbad Energy Center can be shown as RA capacity.[23] As the result of Encina's CPM designation, the LSEs that were not

[20] May 2015 filing, at 2 n.3.

[21] This D. 12-04-046 applies to all of the investor-owned utilities but only impacted San Diego Gas & Electric in this particular case. However, the ISO notes that this may again be a barrier in the future. See ISO reply comments in R. 17-09-020 available at: http://www.caiso.com/Documents/Jun18_ReplyComments_ProposedDecision-RAProgram_R17-09-020.pdf

[22] D.12-04-046, page 27.

[23] The effort to extend the OTC compliance date was a collaborative effort led by the Statewide Advisory Committee on Cooling Water Intake Structures, which includes staff from the ISO, CPUC, California

under Decision 12-04-046's limitations could not secure enough capacity to meet RA obligations and consequently sought a waiver at the CPUC. The ISO further stated in the working group meeting that it believes that a change in the design of the CPM would not have affected the December 22, 2018 procurement and such procurement would have occurred regardless of the CPM price or other design parameters. Stakeholders discussed during the working group meeting whether different remedial measures than the current CPM provisions would not have discouraged LSEs from relying on CPM for forward capacity procurement and whether there is evidence that LSEs have intentionally relied on CPM to an unacceptable extent as a primary means of capacity procurement. The discussion concluded with the ISO stating that this initiative will include consideration of some changes to the design of the CPM. The proposed design changes are discussed in this straw proposal.

8. Next Steps

The ISO will discuss the straw proposal with stakeholders during a meeting on July 11, 2018. Stakeholders are encouraged to submit written comments by August 7, 2018 to initiativecomments@caiso.com. Please use the template available at the following link to submit your comments:
http://www.caiso.com/informed/Pages/StakeholderProcesses/Review_ReliabilityMust-Run_CapacityProcurementMechanism.aspx.

Energy Commission, California Coastal Commission, California State Lands Commission, California Air Resources Board, and the State Water Board.

Appendix 1

List of Acronyms/Abbreviations

AS	Ancillary services
BPM	Business Practice Manual
Calpine	Calpine Corporation
CCA	Community Choice Aggregator
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRI	Center for Renewables Integration
DAM	Day-Ahead Market
DMM	Department of Market Monitoring
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
GFFCs	Going forward fixed costs
GHG	Greenhouse Gas
IEP	Independent Energy Producers Association
ISO	California Independent System Operator Corporation
IOU	Investor owned utility
Joint CCA	East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, and Sonoma Clean Power Authority
LAR	Local Area Requirement
LCR	Local capacity requirements
LSE	Load Serving Entity
MMA	Major-maintenance adder
MOO	Must-Offer Obligation
NRG	NRG Energy, Inc.
OAL	Office of Administrative Law of State of California
ORA	Office of Ratepayer Advocates, California Public Utilities Commission
OTC	Once-through cooling
PGA	Participating Generator Agreement
PG&E	Pacific Gas and Electric
PTO	Participating Transmission Owner
RA	Resource Adequacy
RAAIM	Resource Adequacy Availability Incentive Mechanism
RMR	Reliability Must Run
ROE	Return on equity
ROR	Risk of Retirement
RTM	Real-Time Market
RUC	Residual unit commitment
SC	Scheduling Coordinator
SCE	Southern California Edison
SDGE	San Diego Gas and Electric
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California
SWRCB	State Water Resources Control Board
TAC	Transmission access charge
WPTF	Western Power Trading Forum

Appendix 2

**Stakeholder Written Comments on
March 13, 2018 Draft Final Proposal**

This section provides the full written comments submitted by stakeholders on April 12, 2018. The ISO has summarized these comments and provided ISO responses in section 5.

1. Comments on proposal to make RMR units subject to a MOO.

Calpine – Calpine does not support the imposition of a MOO on Condition 2. First, allowing or forcing a subsidized unit to run at incremental costs has a negative impact on energy prices and hastens the financial distress on other market-based units. Before imposing a MOO, the ISO should simulate the price effects of rapid expansion of C2 units – for instance, by assuming that 5000 MW of thermal capacity was placed on C2. Second, basing the imposition of a MOO on DMM's misplaced representation of a market "distortion" (because prices would rise without a MOO) is shortsighted, and is based on an improper characterization of FERC standards implying that rates are only "just and reasonable" as they relate to "consumers." Certainly, FERC's evaluation of what is just and reasonable considers all market participants, not just consumers. A MOO which drives down market prices to short-run marginal costs is good for consumers in the short run, but very bad for consumer costs in the long run. Third, the ISO's primary, maybe sole motivation to "bolt on" a MOO to Condition 2 is "to make RMR units function more like RA." It seems nonsensical to pattern RMR to a mechanism that itself has failed to secure and compensate the resources needed for reliability. Calpine does not object to a MOO on Condition 1 units, as it is consistent with the market incentives inherent in C1.

CLECA – CLECA supports the ISO's proposal to make RMR-designated resources subject to a MOO as part of Phase 1. This is a comparable obligation to the must-offer requirements associated with units procured under the RA program and the CPM utilized by the ISO. If customers are paying a resource to be available, then the resource should provide its capacity in the market. Without the MOO, supply from these units would be withheld, which does not contribute to an efficient market. This must-offer obligation is supported by all LSE, the ISO's own DMM, and the CPUC in their comments submitted to the prior draft. The only parties that object are certain resource owners, which have failed to provide sufficient justification as to why there should be no MOO. At the stakeholder meeting, some of the resource representatives expressed concern that if an RMR unit would operate more than it has historically then it could result in unrecovered costs. This does not make sense for two reasons. First, any variable costs should be included in its energy bid, which would allow for variable cost recovery if the unit is dispatched. Second, the RMR contract has provisions to recover costs for unplanned repairs and unplanned capital items. Therefore, there is no reason not to make RMR resources subject to a MOO. There is one additional issue that can and should be resolved in Phase 1, which is the issue of RMR or CPM resources providing flexibility. To the extent the RMR and CPM resources provide flexible capacity, their effective flexible capacity should be part of the MOO requirement, and count against the flexible capacity requirement allocated to LSEs as recommended by the CPUC. RMR units under Condition 2 receive a cost of service contract which has provisions to recover existing costs plus possible future costs; thus, there should be cost recovery for all attributes that the unit can provide. Therefore, concerns that the Condition 2 RMR contract never envisioned provision of flexible capacity and that there could be unrecovered costs are unjustified. If customers are paying cost of service for the unit to be available, then they should receive all the attributes the unit can provide. This should be included as a Phase 1 issue, and any adjustments can be made in Phase 2 during the more detailed review of the RMR contract.

DMM – DMM supports a MOO for all RMR units. DMM discussed the benefits of a MOO for RMR units in November 2017 comments on FERC docket ER18-240, stating: The limits on market participation by Condition 2 units are economically inefficient, distort overall market prices, undermine the CAISO's automated market power mitigation procedures, and are unjust and unreasonable for consumers. To ensure mitigation of local market power and avoid artificial inflation of overall market prices, the limits on market participation by Condition 2 units must be removed and a must offer requirement must be established for all units under both Condition 1 and Condition 2 of the CAISO's RMR tariff and contract provisions.1 Obligating an RMR units' Scheduling Coordinator to submit bids (as proposed in this initiative by the ISO) is a major improvement to the ISO's RMR policy and will achieve the economic efficiency and market benefits described above.

IEP – IEP opposes the proposal to make RMR units subject to a MOO in the absence of a more thorough assessment of the potential impact of such change on ISO markets and market-clearing-prices. IEP recommends that DMM conduct an assessment of the market implications of the proposed changes as a pre-condition for the ISO management filing new tariff language implementing the MOO on RMR Condition 2 units. ISO management should commit to studying the market implications of this matter prior to submitting tariff language to FERC. IEP believes that a DMM market assessment could be released to stakeholders no later than May 30, 2018. As a result, the DMM market assessment will inform but not impede nor unreasonably delay the filing of new tariff language imposing a MOO on Condition 2 units (assuming the RMR Condition 2 Unite MOO proposal does not impact ISO markets)

NRG – NRG does not support the proposal to make RMR units subject to an RA-like MOO. The fundamental problem facing the ISO and market participants is this: how did 1,700 MW of capacity deemed essential to the reliability of the ISO's system (Encina, Moss Landing and Metcalf) fail to secure RA contracts? For Encina, the answer can be found in contracting restrictions contained in Decision D.12-04-046. For Metcalf and Moss Landing, the answer may involve other more nuanced matters and issues, such as the RA program's failure to enforce sub-area local capacity requirements or the fact that capital additions are not easily recovered through one-year RA contracts or are not dealt with in the CPM ROR provisions. As all of the ISO Board members acknowledged at the November 2017 meeting in which it authorized the ISO to enter into a stop-gap RMR contract with Metcalf, the failure of the RA program to secure this needed capacity is the fundamental problem to be solved. Instead of addressing this fundamental problem, this initiative promises to focus limited stakeholder energy on the wrong topics, namely, how to turn the RMR contract into an RA confirm and how to modify the ISO backstop procurement mechanisms. Using a contract for a purpose for which it was not intended is an error that should neither be perpetuated nor exacerbated by trying to modify that contract to serve a purpose for which it was not intended. The failure to secure RA contracts resulted in the ISO awarding an RMR agreement for Metcalf to Calpine, and providing CPM designations to Moss Landing and Encina. As a result, the misguided focus of Phase 1 of this stakeholder initiative has been on taking a two-decade old contract (the RMR contract) that was designed to provide the ISO with access to cost based energy when that energy is needed to meet local reliability or address non-competitive congestion, and turning that contract, simply by imposing on it an RA-like MOO, into a vehicle from which to take RA service. The ISO's use of the RMR contract to keep Metcalf in operation, while understandable, is a misguided, or at least suboptimal, use of that agreement. The ISO has CPM ROR provisions that it could have used to keep Metcalf in operation but chose not to use for Metcalf. If those CPM ROR provisions were unsuitable for keeping Metcalf in operation due to that plant's individual circumstances, then the CPM ROR provisions should be re-examined and modified as needed to make the CPM ROR provisions suitable for use as an RA backstop mechanism. Instead, by using the RMR contract to keep a unit that should have been procured through the RA program in operation, the ISO and stakeholders are now engaged in a process to try to turn the RMR contract into a vehicle for taking RA service – something it was never intended to do. The irony of this outcome is that while, at the last ISO meeting in this initiative, no party claimed to want to use the RMR contract in this way again, several of those parties nevertheless insist that the ISO press forward with this stakeholder process to modify the RMR contact for that very purpose. This is a bad use of everyone's time and energy. This ISO initiative should not compete with, and distract parties' energy and attention from, the real need, which is to fix the RA process – more specifically, to adopt a multi-year forward RA structure that provides needed resources with certainty over a more rational time frame to plan and conduct needed maintenance. In sum, NRG urges the ISO to: (1) Suspend this initiative, allowing all parties to focus their efforts at RA reform in Track 2 of the CPUC's RA proceeding. RA reform, properly developed and implemented, should minimize or eliminate the need for any CAISO backstop mechanism, let alone two backstop mechanisms. Creating a CAISO backstop mechanism that all parties agree on and is suitable for procuring RA service simply dilutes the need to get the RA program rules right. (2) Take up Phase 2 only after the CPUC has finished Track 2 of the RA proceeding. If Phase 2 proceeds nevertheless, its only foci should be (a) to address the load migration issue for annual CPM designations, and (b) to create a single CAISO backstop mechanism. The ISO should not have two competing and conflicting backstop mechanisms (one of which is not really a backstop mechanism, but an outdated contract that provides the ISO with access to cost-based energy to mitigate the potential to exercise local market power).

ORA – ORA supports adding a MOO to future RMR contracts but has concerns with the proposed language regarding energy bid calculations. The Draft Final Proposal states that cost-based bids of Condition 2 RMR units can include MMAs. The energy bids of market resources include commitment costs which sometimes include MMAs which increase energy bid prices in order to recover certain maintenance costs. In the case of an RMR resource however, capital item cost recovery may include major maintenance items in Schedule L-1 of the RMR contract, independent of energy bid price calculations. It is unclear why an MMA would be necessary for additional cost recovery for RMR agreements. It is unclear how MMAs are related to the dispatch of an RMR resource and why they should be included in the calculation of RMR energy bids when Schedule L-1 may cover maintenance costs. Inclusion of MMAs would increase the bid price of the unit and could decrease how often it is dispatched on the market. Less competitive prices from RMR units may lead to a higher price of energy in the market and/or dispatch of more costly resources as alternate energy bids are selected by the ISO market processes. MMAs should not be included in the energy bid price, and should be removed from the Draft Final Proposal. If ISO instead chooses to keep MMAs in the Final Proposal, a description of RMR- specific MMAs is required. There appears to be no provision in the pro forma RMR agreement specifying MMA treatment. If MMAs are not removed from calculation of energy bids in this proposal, ISO should define "major maintenance adder" in the Final Proposal to ensure that MMAs are distinct from Capital Items, as described in the pro forma RMR agreement, to prevent duplicative cost recovery through Schedule L-1. The definition should include justification for the inclusion of MMAs if MMAs are to be used in cost-based energy bid calculations.

PG&E – PG&E supports (with some conditions described further below) the ISO's two Phase 1 proposals: inclusion of a MOO for RMR units, and the proposed business process change to allow notification of market participants upon ISO receipt of new risk-of-retirement letters from resource owners (as well as disclosure of letters ISO may already have received but not disclosed thus far in 2018). Despite our support for these Phase 1 measures, PG&E remains concerned that the scope of Phase 2 falls well short of the challenge at hand and that inefficient, costly backstop procurement in the coming years remains a likely outcome. In previous comments, PG&E proposed three Phase 2 scope additions that would help to more completely address the scale of the problem in California's local capacity markets. All three were rejected by the ISO for reasons that appear to display a lack of willingness to engage with the seriousness of the issues: (1) "Going Forward" Cost as Basis for both ROR CPM and RMR: The ISO asserts that the compensation mechanisms for backstop procurement in the tariff were found just and reasonable at FERC at their time of approval, 1 and therefore "the ISO is not planning to significantly change in this initiative the overall compensation structure." (Draft Final Proposal, p. 14). (2) Inclusion in scope of changes to the TPP and LCR study process to identify needs earlier: The ISO asserts that "the issues are already adequately addressed in the ISO tariff and current processes." (Draft Final Proposal, p. 15) (3) Removing the ISO's discretion whether or not to CPM for a collective deficiency: "([CAISO is] not planning to change the tariff language from 'may' to 'shall') as this language was approved by FERC". (Draft Final Proposal, p. 15). The ISO's logic in rejecting all three of PG&E's proposals appears circular. PG&E reminds the ISO that the purpose of this initiative is precisely to review and revisit those portions of the tariff that are no longer in accord with policy and that are producing (and will likely continue to produce) outcomes that are unjust and unreasonable, in light of changed circumstances. PG&E provides the following additional comments on features of the Draft Final Proposal. The ISO's proposal for Phase 1 has not described how the MOO will reflect the use-limited nature of RMR resources within the market. The ISO's draft final proposal for Phase 1 of this initiative is intended to immediately address and implement a MOO for RMR units, comparable to RA and CPM resources. The SC will be required to submit market based bids for energy and AS during all hours that the unit is physically available. The intent of implementing a MOO for RMR units is to ensure that the resource isn't withheld from participating in the ISO markets during all hours, in the interests of the consumers who are bearing the full cost of the RMR capacity receiving value from the resource. Market participation is important to extracting the value of the contract cost. However, ensuring that the unit is available for RMR Dispatches is also important to reliability. The ISO should provide additional details to describe how it will implement the use plan that identifies and preserves the specific hours for RMR dispatch operation while requiring market participation during other periods. The ISO has not accurately estimated RMR dispatch hours for the units which are designated for specific reliability reasons today, and ensuring market participation could result in units being unavailable for RMR dispatches. The ISO should describe in more detail how it will optimize within the market how it instructs an RMR unit not to run due to a use limitation. Additionally, the ISO needs to be able to accurately estimate both projected market and reliability dispatches to determine whether any capital improvements are justified. The ISO's proposal for Phase 1 should use the non-performance penalties to incent performance for both the RMR Dispatches and Market Transactions. The ISO's draft final proposal recommends that the current RMR penalties in the RMR agreement be used to incent performance. The RMR unit is exempt from RAAIM performance penalties and is subject to Nonperformance penalties pursuant to the tariff. Non-Performance Penalties include both the hourly availability charge associated with the fixed revenue requirement and the hourly capital item charge associated with any capital expenditures. Non-performance penalties are only applicable when the resource isn't available for an RMR dispatch and will not apply during any other hours. The ISO has proposed to impose a 25 percent reduction of the daily fixed revenue requirement if the unit owner, after consultation with the ISO, has not fulfilled its obligation to submit bids during all hours. The ISO should impose the Non-performance penalty, which includes the fixed revenue requirement and any capital expenditures, for a unit's failure to meet the must offer obligation The ISO's proposal for Phase 1 should not include major maintenance adders in ISO generated cost-based bids for RMR Dispatches. The ISO's draft final proposal indicates that in instances when the ISO generates and inserts cost-based bids that major maintenance adders will be included within the start-up costs. RMR resources have separate tariff provisions pursuant to Schedule L-1 to propose capital items for the next contract year and a five-year forecast of anticipated capital expenditures. These capital costs are proposed and recovered separately from its market operation. Including major maintenance adders in the cost based bids could prevent the unit from being dispatched more frequently within the market while it still obtains recovery of capital costs that have already been approved separately. The ISO's proposal should account for all the RA characteristics associated with the RMR capacity. By rendering a must-offer obligation for RMR capacity, the ISO should make sure that the value of the services being procured are recognized. RMR contracts are providing for a specific reliability need, but also, with the addition of the MOO, providing what are essentially RA services. This recognition needs to be effectuated so that there is not the over procurement of unneeded RA capacity. RMR capacity with a MOO is providing services exactly akin to capacity counting for system, local and flexible

RA, and should be accorded that credit. Consequently, the ISO should facilitate the counting of these RA attributes by allowing the capacity to be allocated directly to LSEs or the recognition that the LSEs responsible for paying the RMR costs should be getting the RA credit from that capacity, either through the reduction of the requirements for those LSEs or for the direct allocation of that capacity through setting LRA requirements. Failure to do so would lead to un-just and unreasonable required procurement on the part of the ISO. The ISO should also address the load migration issues associated with annual CPM calls. Under the current tariff, the ISO allocates the costs of annual CPM to LSEs based on the forecast of load at the time the call is made. However, it is possible for load to migrate between LSEs between the time the ISO makes the CPM designation, before the beginning of the year, and the time the CAISO actually bills LSEs for the CPM. Monthly CPM costs are allocated on an ex post basis, and the ISO could easily change its allocation to be based on actual load. Not to acknowledge the load shift between LSEs leads to unjust and unreasonable charges for services beyond those incurred by load. PG&E suggests the ISO make the following tariff language change: 43A.8.3 Collective Deficiency in Local Capacity Area Resources If the CAISO makes designations under Section 43A.2.2 the CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs serving Load in the TAC Area(s) in which the deficient Local Capacity Area was located. ~~The allocation will be based on the Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43A.2.1.2 on a proportionate basis, to the extent of their additional procurement.~~ CAISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the need for the CPM designation arose based on the percentage of actual Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total Load in the TAC Area(s) as recorded in the CAISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.

SCE – The MOO is not sufficient. While SCE agrees with the need for a MOO, it does not see the value in a MOO which lacks any incentives against non-performance. The ISO procures RMR resources for reliability and compensates them at least consistently with that of an RA resource, however, the ISO proposes to not have the same non-performance penalties on RMR resources that it does on RA resources. Such a proposal undermines the RA process by setting up incentives for resources to prefer the backstop over RA. SCE does not support any policy that either lacks appropriate incentives or undermines RA – the proposed MOO falls in both categories. Further, the proposal to have the RMR capacity bid into RUC at $0 only if the ISO resorts to bid insertion, is insufficient. Customers are already paying the resource for its entire RMR capacity. If a resource chooses to bid high enough, it may not clear the market and the capacity is withheld. SCs for RMR resources should be required to bid $0 in RUC, failing which the ISO should insert a bid in RUC at $0 on behalf of the RMR resource. Load migration cost allocation should be addressed in phase 1 During the March 20th meeting, the ISO stated that load migration cost allocation should be in phase 2 because it is a contentious issue. First, delaying topics because they are contentious is not an appropriate policy. Second, any delay leads to further cost allocation that is not just and reasonable. All of the RA attributes of procured resources should be accounted and credited. SCE fails to understand why this is not an immediate outcome of this initiative. The ISO is proposing changes to a reliability mechanism that compensates resources at least consistent with RA payments. At the least, all resource attributes relevant to RA should be accounted for and credited to the customers that are paying for these resources. As stated by the CPUC Staff during the call, the ISO could end up with the perverse outcome of entering into an RMR with a resource that the ISO needs the flexible capacity from yet, the RMR will not convey that attribute leaving the market further at risk for not obtaining the correct amount of flexible resources.

Sierra Club – Sierra Club supports making RMR units subject to a MOO, but has the following two concerns with the final draft proposal. (1) RMR Contracts Should Include the Allocation of Flexible RA Capacity – The draft final proposal fails to maximize ratepayer benefit of contracts by deferring the topic of allocating flexible RA capacity of an RMR resource. As CPUC Staff noted in its February comments, "[t]he current RMR contracts do not cover the procurement and allocation of flexible capacity. Since ratepayers are paying for all of the costs associated with the operation and dispatch of these resources they should be allocated the flexible capacity attributes of the resource." The draft final proposal does not incorporate this suggestion, but rather states it may be within the "possible scope of Phase 2." While CPUC Staff state that it believes this would be a small modification to the RMR tariff, the SO fails to provide any response as to why allocation of flexible RA capacity is not included in Phase 1. Indeed, the recently filed settlement between ISO, Calpine, and PG&E regarding the RMR contract for Metcalf specifically includes allocation of Metcalf's Effective Flexible Capacity to applicable LSEs as part of its MOO. There does not appear to be any legitimate reason why allocation of flexible capacity cannot be similarly included in RMR contracts going forward. Accordingly, the Draft Final Proposal should be amended to specifically include allocation of Flexible RA before it is presented to the ISO Board for approval. (2) Bids Should Not Include MMAs – In describing the submission of energy and AS cost-based bids by the SC under Condition 2 RMR Units, the draft final proposal states that the "SC can include opportunity costs and MMAs in bids." It is Sierra Club's understanding that RMR contractual costs already account for cost of service, which would include maintenance. Since these costs are accounted for, it is unclear why the SC should then again be able to include an MMA. The ISO should clarify or remove this term prior to finalizing its proposal.

Six Cities – The Six Cities strongly support application of a MOO for energy and AS to RMR Condition 1 and 2 resources. Conceptually, RMR resources receive compensation for capacity costs to ensure that they remain available to the ISO's markets. In the context of RA capacity and capacity procured under the ISO's CPM, the ISO assesses availability through compliance with MOOs. For the same reasons that MOOs apply to RA capacity and CPM capacity, RMR resources should be required to comply with MOO for any and all products that the RMR resource is capable of supplying.

2. Comments proposal for ISO to provide notification to stakeholders that a resource is planning to retire.

Calpine – Calpine does not object to disclosure of those units that are seeking an evaluation of the reliability-based need for that resource. We do, however, assert that notice of “retirement” is too narrow and should include all forms of unavailability permitted under the tariff. This would include a notice of termination of the PGA, removal of units from the PGA schedule 1, mothballing, and repowering requests. We also support a similar market participation notification when the reliability analysis is completed.

CLECA – CLECA supports the proposal that the ISO provide a market notice that it has received a notification that a resource may retire. This will provide more transparency to determine if the resource is needed for reliability and allow the market to present alternatives, if they exist, before the resource is offered a risk of retirement contract by the ISO.

NRG – NRG does not object to this aspect of the proposal set forth by the ISO, which involves providing market-wide notice of key information when the ISO receives a retirement notice, but does not involve posting the actual retirement notice.

ORA – ORA supports the amendment to the Draft Final Proposal that requires ISO to notify stakeholders when a resource owner indicates that its resource may retire. This proposal is consistent with ORA’s recommendations to increase transparency to facilitate informed procurement and ratemaking decisions for RA. In the March 20th stakeholder meeting, the ISO stated that it had already received some notices from resource owners seeking analysis to determine if their resources could retire. ORA requests that ISO provide those communications to stakeholders as soon as possible. The ISO clarified that it intends to notify stakeholders when the resource owner states that it is considering mothballing the resource or making the resource otherwise unavailable to the ISO. In other words, notification would not be limited to situations when the resource owner mentions retirement. ORA requests that the ISO include this clarification in its written proposal. The ISO proposes to notify stakeholders through a market participant communication when it receives a notice from a resource owner about a potential retirement. It is not clear if the ISO intends to provide the information through market notices, which are available to all interested stakeholders, or through another process only available to market participants. ORA requests that the ISO provide the information through market notices to inform all interested stakeholders who may not necessarily participate in the market, such as ORA. The ISO states that it “will not post the actual owner’s notification letter, but will summarize the key information from the notice such as the date received, affected unit and requested retirement date.” It is not clear why the ISO is not proposing to provide the actual notice. A representative from NRG has stated that they have submitted notices to the ISO and that the notices are not confidential. ORA requests that the ISO modify its proposal to also include the actual owner’s notification letter.

SCE – SCE supports the ISO proposal to make public information about resources planning to retire.

Sierra Club – Sierra Club supports notification to stakeholders that a resource is planning to retire. However, the draft final proposal should be clarified and improved by: (1) defining a timeline for notifying stakeholders; and (2) making the written notice available to stakeholders. First, the draft final proposal does not appear to define the timing between when a retirement notice is received and when stakeholders are notified. Sierra Club recommends that the ISO commit to notifying stakeholders no later than 5 business days from receipt of notice. Second, the draft final proposal notes that ISO will notify stakeholders by summarizing the key information included in any notice that a resource may retire, but declines to post the actual notice. This change would provide some additional degree of transparency, but stakeholder transparency would be further advanced by making any such written notices publicly available. Stakeholders have a vested interest in understanding any stated justifications for why the resource plans to retire. To the extent a particular notice contains market-sensitive information, this portion can be redacted.

Six Cities – The Six Cities also support this aspect of the Phase 1 draft final proposal

3. Comments on potential phase 2 items.

Calpine – Counting Flex Attributes – The CPUC has suggested that as part of phase 1 that the ISO establish a method for counting and allocating the flexible attributes of RMR resources. Calpine supports the proposal to reduce the overall demand for Flexible Capacity as a result of RMR contracting.

Imposing MOO on Condition 2 - Calpine believes that consideration of imposing a MOO on Condition 2 units should be deferred to a later phase of this initiative once more is known about the RA reforms.

Combining CPM and RMR - Calpine encourages the ISO to be more specific with respect to the tariff provisions it envisions might be subject to consolidation. If the ISO is suggesting that CPM ROR designations (43A.2.6) be combined with RMR, Calpine supports that proposal. In fact, we believe that 43A.2.6 can be struck from the tariff with no ill consequences. We continue to believe that all other designations under CPM (43A.2) continue to hold value and will be effective, and will operate better (if needed at all) if RA showings are required earlier in the calendar year (like June 1).

Review the Rate of Return in CPM and RMR - While Calpine does not object to an evaluation of the pre-tax Rate of Return ("RoR") built into the tariff, Calpine believes there are much higher reform priorities and this should be deferred. If the ISO does reconsider the level of the "plug" RoR, it is likely that given the risks in this market Calpine will seek a higher, certainly not lower pre-tax RoR. The 12.25 percent rate of return embedded in the RMR and CPM tariffs is a pre-tax number that cannot be compared directly with the commonly reported after-tax, debt/equity-adjusted IOU rate-of-return, or return-on-equity. In fact, to convert a pretax RoR to an after-tax RoR, the ISO (and eventually, FERC) would have to determine the applicable tax rate of each project (not each entity), its debt costs, its equity costs and the ratio of debt-to-equity. It would also need to restructure Schedule F significantly in order to provide a "gross-up" for taxes. That is, since an after-tax RoR is subject to income taxes, the Schedule F formulas would have to be modified to increase the top line revenue requirement (Schedule F, Line 1(A)(1)) by this tax effect. In addition, Calpine believes that the RoR for incremental capital expenditures would have to be significantly higher than 12.25 percent pre-tax to accommodate the related matters of highly accelerated depreciation and book-versus-tax timing differences.

Simplify RMR Invoicing/Settlement - After having navigated the RMR invoicing labyrinth, Calpine may be the most passionate advocate of RMR settlement simplification. The redundancy and administrative barriers drive to excessive transaction costs and delay. However, until the ISO has a better view of RA reforms – and the resultant demand for RMR contracting. Calpine urges rational caution and reasonable expenditures on reform.

Expand tariff authority under RMR - Calpine does not object to a clarification of the ISO's authority to manage reliability, including, as necessary the acquisition of attributes (such as flexibility) necessary to manage reliability.

Consider whether RMR Condition 1 and Condition 2 designations are still needed - Calpine sees no need eliminate either Condition 1 or Condition 2 at this point. Consideration of such should only occur after a holistic review of RA reforms. In addition, the ISO is currently evaluating operational options for storage (see Storage as a Transmission Asset) identical to the optional conditions of RMR. No limitations on RMR should be established that would be inconsistent with, or create undue discrimination with those proposed by the FERC Policy Statement on Storage Resources.

Allow for capital additions - As energy margins decline, it will be increasingly necessary to consider mechanisms to recover the costs of incremental capital. No rational business will invest incremental capital (for maintenance, flexibility or improvements) without a clear path to collect a return of (in the form of depreciation), and a return on (in the form of carrying costs, debt/equity) that investment. The ISO's backstop mechanism, whether RMR or a modified CPM, must include provisions to ensure that incremental capital earns a reasonable return.

CLECA – CLECA ranks the Phase 2 items with the following priority: 1 Work with the CPUC to develop a schedule or other mechanism that could avoid a collective deficiency and appropriately address the cost allocation for such a deficiency in the context of load migration. In the annual RA showings for compliance year 2018, the CAISO determined that there was a collective deficiency in the RA portfolios presented to it for meeting local RA requirements. This led the ISO to sign contracts with several units under its backstop CPM. CLECA, and other parties, have stated their concerns over the process which has resulted in procurement in excess of the total RA MW required, which in turn, creates excess costs which are passed onto customers. 5 CLECA understands coordination with the CPUC is complex and CLECA urges the ISO to work to find a solution in this Phase 2 process and/or the CPUC's RA process that facilitates the procurement of RA resources that fully cover local RA needs without backstop procurement. The cost recovery of collective deficiency is a problem when there is load migration to community choice aggregators ("CCA"). The current ISO tariff in Sections 43.8.3 and 40.3.2 allocates the costs based upon an LSE's proportionate share of the TAC Area load at the time of the annual peak demand forecast for the next RA compliance year. To the extent load migrates to another LSE, it is unjust and unreasonable for one LSE to pay for the reliability for another LSE. Phase 2 should examine the issue of cost allocation due to load migration in coordination with the CPUC's RA proceeding. 2. Any flexible capacity value from RMR and CPM units should be allocated to LSEs. Customers are paying for the resources, so they are entitled to all capacity and ancillary services value. This includes flexible capacity attributes. Participants should receive an allocation of their effective flexible capacity. If possible, this should be resolved as a Phase 1 issue. 3. Revise the terms of RMR for today's RA process and clarify when RMR and CPM are used. The RMR contract was designed at the formation of the ISO when certain units were needed for local reliability, but the IOUs were not able to sign long-term contracts and market power mitigation rules were being developed. Today there is an RA program, so parties can sign long-term contracts for local reliability and market power mitigation rules are more robust. It is time to modify the terms of the RMR contracts to meet current conditions. In addition, greater clarity is needed as to when and under what circumstances RMR vs. CPM is utilized. This is necessary to determine what capital costs are recovered under each contract type. (See next section for more discussion.) The ISO plans to use the penalties for non-performance in the RMR agreement to incent performance as opposed to the using the RAAIM. 6 The RMR contract has no penalties if the unit notifies the ISO of a forced outage, whereas RA units are subject to RAAIM which does have a penalty for poor availability performance. This difference could lead resources to favor RMR due to less stringent performance standards. Thus, CLECA is concerned that use of the penalties for non-performance in the RMR agreement is insufficient and recommends the ISO further consider this issue in the Phase 2 process. 4. Rate of return values for RMR or CPM should be the same and be updated as the cost of capital changes. The cost of capital changes over time, and it should be updated as in any cost of service contract. To the extent CPM needs a cost of service rate of return, it should be the same as RMR. (At this time CLECA is not endorsing a cost of service rate of return in a CPM contract, as the merit still needs to be reviewed.) Otherwise there is an incentive for parties try and get the more lucrative contract. 5. Allocation of RMR or CPM when the local need spans across TAC Areas, such as LA Basin and San Diego.

DMM – The second phase of this initiative has a larger scope and longer timeline. The ISO is currently finalizing the agenda items for phase 2. It is critical that the ISO address RMR compensation in phase 2. RMR compensation currently allows RMR units a return on what the ISO calls the "full fixed cost of service" (i.e., sunk capital costs minus depreciation). DMM believes that compensating a resource based on its full sunk capital costs (after depreciation) is unjust and unreasonable. The ISO contends that FERC requires compensation at "full fixed cost of service" value. This is not correct. FERC has ordered that some fixed cost recovery is reasonable, but has left room for RTO/ISOs to negotiate an appropriate RMR rate somewhere between going forward fixed costs and full fixed cost of service. In a 2015 NYISO RMR tariff filing FERC stated, "[c]ompensation to an RMR generator must at a minimum allow for the recovery of the generator's going-forward costs, with parties having the flexibility to negotiate a cost-based rate up to the generator's full cost of service." In 2011, the Commission did not approve a CPM filing by the CAISO based in part on concerns that basing compensation on "going forward costs may create the potential for distorted pricing signals and deny resources a reasonable opportunity to recover fixed costs" and that the CAISO did not explain "how the use of going-forward costs for CPM compensation will provide incentives or revenue sufficiency for resources to perform long-term maintenance or make improvements that may be necessary to satisfy new environmental requirements or address reliability needs associated with renewable resource integration." In a subsequent 2015 tariff filing and Offer of Settlement, the CAISO proposed increasing compensation for CPM resources through a "soft cap" based on an updated estimate of going forward fixed costs of a typical unit plus a 20 percent adder. As explained in the CAISO's 2015 filing: […] the CAISO will procure backstop capacity through a competitive solicitation process and pay designated resources their bid price. A soft offer cap will apply to all offers into a competitive solicitation. The soft offer cap is based on the estimated levelized going forward fixed costs of a merchant-constructed, mid-cost, 550 MW combined cycle unit with duct firing, as reflected in a cost study conducted by the California Energy Commission, plus a 20 percent adder. Although the CPM soft cap is explicitly based on GFFC (plus a higher 20 percent adder), the CAISO's 2015 tariff amendment and offer of settlement also changed the basis for cost justification (for compensation in excess of this soft cap) from GFFC to the AFRR calculation used for RMR condition 2 units. As noted in the 2015 filing: Resources have the option to make a filing with the Commission to cost justify a price higher than the soft offer cap based on the formula applicable to Reliability Must Run Resources. These pricing provisions [i.e. the higher soft offer cap and opportunity to justify costs in excess of this cap based on AFRR] respond to the Commission's guidance to provide enhanced fixed cost recovery opportunities to CPM resources. The CAISO's 2015 filing went on to explain that: This CPM Soft Offer Cap adopted in the Offer of Settlement is just and reasonable, in the public interest, and a necessary complement to the competitive solicitation processes. Combined with the opportunity to make a resource-specific cost filing that can take into account all fixed costs (not just going-forward fixed costs), it is simultaneously high enough to ensure contributions to fixed cost recovery and low enough to provide appropriate market power mitigation. When approving the CAISO's proposed soft cap for CPM compensation later in 2015, the Commission specifically found that: CAISO's proposal to implement a soft offer cap of $6.31/kW-month ($75.68/kW-year), plus a 20 percent adder should allow sufficient recovery of fixed costs plus return on capital to facilitate incremental upgrades and improvements by resources. Further, because the soft offer cap represents the high end of the range of current resource adequacy prices, it should not create incentives for load serving entities to forego bilateral resource adequacy contracts and, instead, rely on CPM backstop procurement. The Commission's 2015 Order did not indicate that providing guaranteed recovery of sunk fixed costs plus a return on investment was needed to address the Commission's prior concerns. Thus, DMM believes the ISO's CPM and RMR provisions can and should be modified based on the key market design principle that resources with market power should be mitigated based on going forward fixed cost. If needed, specific targeted provisions can be added to CPM and RMR provisions to address the Commissions prior concerns about setting cost-based compensation high enough to ensure proper long-term maintenance and incremental upgrades may be needed to "satisfy new environmental requirements or address reliability needs associated with renewable resource integration."

Joint CAA – East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy Authority, and Sonoma Clean Power Authority ("Joint CCAs") appreciate the opportunity to provide comments. In the DFP, the ISO discusses potential phase 2 items, which the ISO envisions to be implemented in Fall 2019 to be in effect for 2020. As part of this discussion, the ISO notes concerns from stakeholders on the need for coordination with the CPUC RA proceeding, and the need for improvement with the RA compliance timeline. For example, CPUC staff requested, among other things, that future ISO straw proposals include coordination with the RA procurement process. Though the ISO states in the DFP that it is "not planning in this initiative to move the RA timeline back" as a means to revise the existing RA program, the ISO is open to proposals for program improvements in phase 2. The Joint CCAs propose "Sub-Local RA Voluntary Targets" and complementary ISO coordination to improve the RA program and reduce backstop procurement issues highlighted in the DFP. In order to ensure grid reliability, the ISO has the authority to procure backstop capacity to cure a collective deficiency in a local capacity area. Unfortunately, such backstop procurement results in excess capacity procurement in specific local areas, as LSEs have already procured other local resources in accordance with their compliance obligations. The costs associated with such excess capacity are borne by LSEs within the ISO and ultimately by their customers. Accordingly, the Joint CCAs believe that it is important to explore ideas to improve the local RA process to reduce avoidable backstop procurement costs. Sub-Local RA Voluntary Targets can be an effective means to improve this local RA process. In accordance with current local RA requirements, ISO LSEs today are not required to secure capacity in any of the 45 sub-local areas as defined by ISO. Instead, due to market power concerns, LSEs are required to secure capacity at the local area level. Unfortunately, these less granular requirements do not ensure that the right local resources will be procured to mitigate reliability risk. These requirements then can lead to backstop procurement that results in excess capacity and added costs that could have been avoided. Accordingly, the Joint CCAs suggest that LSEs be assigned Sub-Local RA Voluntary Targets. These targets are voluntary, so there is no additional risk of RA penalties. The targets are neither a ceiling nor a floor, and simply communicate more specific needs by area. In conjunction with these targets, the Joint CCAs also recommend that the CAISO revise its CPM tariff. The Joint CCAs understand that some aspects of this proposal are CPUC-specific, and have provided the full proposal at the ISO in an effort to encourage coordination on these issues among organizations and stakeholders. A. Summary of the Structure for Sub-Local RA Voluntary Targets To implement these voluntary targets, Local obligations would be amended to include sub-local targets in the year-ahead RA process when LSEs receive their obligations (July) and revised obligations (September), which are provided to the LSE in a confidential manner. For example, under current RA program, a CCA program in PG&E's transmission area might have the following local RA requirements (which are purely illustrative) as specified in the "LSE Allocations" tab of the CPUC's Year-Ahead or Month-Ahead compliance file: • Bay Area Local Obligation = 100 MW • Other PG&E Local Area Obligation = 125 MW With the "Sub-Local RA Voluntary Targets", the example directly above would be amended, as shown below: • Bay Area Local Obligation = 100 MW • Moss Landing Sub-Local Voluntary Target: 11 MW • Oakland Sub-Local Voluntary Target: 8 MW • Etc. • Other PG&E Local Area Obligation = 125 MW •

Humboldt o Humboldt Sub-Local Voluntary Target: 7 MW • North Coast / North Bay o Eagle Rock Sub-Local Voluntary Target: 3 MW o Fulton Sub-Local Voluntary Target: 2 MW o Etc. • Sierra Local Area o Pease Sub-Local Voluntary Target: 5 MW o Placerville Sub-Local Voluntary Target: 4 MW o Etc. • Stockton o Stanislaus Sub-Local Voluntary Target: 6 MW o Weber Sub-Local Voluntary Target: 1 MW o Etc. • Greater Fresno o Coalinga Sub-Local Voluntary Target: 7 MW o Hanford Sub-Local Voluntary Target: 2 MW o Etc. • Kern o West Park Sub-Local Voluntary Target: 4 MW o Kern Oil Sub-Local Voluntary Target: 4 MW o Etc. Importantly, the amended example above includes sub-local targets that would (if procured) contribute to the LSE's local area obligations. In other words, the sub- local targets would not be in addition to the local area obligations. B. Proposed CAISO Tariff Revisions to Reward Voluntary Sub-Local Procurement In conjunction with proposing Sub-Local RA Voluntary Targets for LSEs, the Joint CCAs also recommend that the ISO revise its Tariff (specifically, Section 43A.2.2.1) to reward LSEs that voluntarily procure their sub-local targets. Specifically, the Joint CCAs recommend that in the case where the ISO CPMs are conducted to address collective deficiencies in local capacity areas, the associated costs should be allocated (proportionately, based on MW not procured) only to those LSEs that did not fully procure both their local RA obligations and their sub-local voluntary targets. As the ISO tariff exists presently, there is no way for an LSE to fully avoid collective deficiency CPM costs, even if the LSE procures the ISO-specified resources during the 30-day cure period. By revising the ISO's CPM tariff in the manner suggested above, LSEs will be motivated to procure their sub-local targets (and avoid CPM cost exposure), helping to avoid the need for the ISO CPMs in the first place. C. Need for the ISO Coordination on RA Program Improvements. The CPUC is presently examining changes to its RA program through Rulemaking 17-09-020. An issue for discussion has been the possibility of a multi-year procurement structure. Related to the sub-local issues above, the Joint CCAs have proposed that in year 1 of any multiyear procurement structure, the CPUC would adjust local RA year-ahead requirements to cover 90% of the RA Requirements ("RAR") for all 12 months of the applicable compliance period, aligning procurement with the percentage coverage of system and flexible RA. The LSE would then procure the remaining 10% Local RAR after the year-ahead deadline to adjust to specific local needs and in response to the CAISO's Evaluation Report of local and system requirements. This approach addresses the issue highlighted above where the overall local procurement may be sufficient, but there still may be needs to address local sub-areas, which in turn impacts ISO backstop procurement determinations. Thus, the subsequent 10% adjustment would allow LSEs to adjust procurement to cover any identified local needs, and work to alleviate backstop procurement issues. The Joint CCAs encourage the ISO to coordinate with the CPUC on local procurement adjustments following the year-ahead deadline, and address any changes in phase 2 as needed. D. Conclusion In summary, the Joint CCAs recommend three items: (1) working together, the CPUC and ISO should implement sub-local RA voluntary targets for LSEs within ISO, and such targets should be provided in tandem (i.e., in the same upfront timeframe) as RA obligations are provided; (2) the ISO should revise its tariff to allocate local capacity collective deficiency CPM costs only to those LSEs that did not fully procure both their local RA obligations and their sub-local voluntary targets; and (3) the ISO should coordinate with the CPUC on changes as related to Local RAR improvements. The Joint

CCAs believe that these changes will lead to more effective local capacity procurement. Stakeholders may point out that this proposal appears to ignore some of the realities facing generators. For example, a 600 MW generator may not be enticed to sell 4 MW of capacity to an LSE that is looking to fill its sub-local target. However, with proactive demand for the right local resources, the market has a better chance than it does today to arrive at an efficient solution. For example, a 600 MW generator might receive a number of inquiries/bids and may decide to hold an RFO. This mechanism would also incentivize LSEs to jointly procure the resource. At a minimum, there can be greater transparency into the resources required by the ISO for reliability, and LSEs have the chance to avoid double procurement. In conclusion, the Joint CCAs believe that these changes will facilitate better transparency and more efficient local capacity procurement, while protecting the procurement autonomy of LSEs and the backstop procurement authority of the ISO.

NRG – NRG offers this ranked priority list (from high to low) of, and comments on, proposed Phase 2 items: 2. Merging RMR and CPM into a single backstop procurement mechanism. This will allow the CAISO to delete items 1, 5 and 6 and to change the scope of items 7 and 8 to focus solely on the single backstop procurement mechanism. This mechanism should provide service equivalent to RA service. Items 3, 4 and 9 then should be taken up under this effort to create a single backstop procurement mechanism. 10. Review the year-ahead CPM cost allocation to account for load migration. While the cost allocation of the CAISO's backstop procurement could be taken up under the effort to produce a single backstop procurement mechanism, this issue should be less a policy matter than a timing matter and could be addressed on its own. 11. Evaluate if LSEs are using CPM as a primary means for capacity procurement. NRG strongly believes that the RMR and CPM procurement at the end of 2017 was not the result of LSEs or suppliers suddenly deciding that they now prefer these two mechanisms over RA contracts, but, in significant part, of limits placed on LSE contracting by CPUC decisions and the failure of the RA program to ensure needed resources receive RA contracts. Consequently, this effort should have the lowest priority.

ORA – A. RMR and CPM Issues i. ORA Does Not Support Expansion of Authority to Backstop to Integrate Renewables CAISO proposes to expand its tariff authority to designate RMR and CPM resources based on "integration of renewable resources in order to reliably operate the grid." This proposal is overly broad and unnecessary. Stating that a resource could be designated for RMR and CPM to integrate renewables is too vague to justify backstop procurement. Backstop procurement should be based on clearly defined reliability standards and numerical criteria, not a general statement that a resource is needed to integrate renewables. Additionally, current RA requirements and the integrated resource planning (IRP) process are already designed to address renewable integration. The CPUC adopts flexible RA requirements annually based on the ISO's Flexible Capacity Needs Assessment to address net-load ramps caused by increased renewables penetration. The CPUC has also created an IRP process to "(i)dentify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner." Given current available mechanisms to integrate renewables, the proposal to expand CAISO's authority for backstop procurement to address the same issue is unnecessary and should be removed. ii. ORA Supports Consideration of Alternative Resources ORA previously expressed concerns that the current RMR process leaves no time for consideration of alternative solutions and instead provides generators with information about their market position. Other parties expressed similar concerns that the current process for the ISO's backstop mechanisms does not facilitate review of alternative market or transmission solutions. The inability to develop alternative solutions can increase ratepayer costs and exacerbate local market power issues. ORA continues to recommend review of the current process for backstop procurement to provide an opportunity to consider alternative solutions before backstop procurement. iii. ORA Supports Consideration of Payment and Penalty Issues ORA supports investigation of both RMR and CPM processes to ensure bilateral market agreements remain the preferred and primary platform for capacity procurement so that CPM and RMR designations are used sparingly. The RA program was designed to facilitate capacity procurement through competitive solicitations and enable LSEs to meet their reliability requirements through self-owned and contracted resources at a reasonable cost for ratepayers. Increased use of RMR and CPM could negatively impact competitive RA solicitations and result in higher costs for ratepayers. The March 20th the ISO presentation included a brief discussion concerning possible unintended incentives which may make CPM or RMR preferable for generators as opposed to typical RA market agreements. Outage penalty structures and other forms of penalties and compensation reviewed in this initiative could potentially lead to increased RMR and CPM designations if they offer generators more revenue for capacity and more lenient requirements compared to the RA market. ORA also supports continued refinement of CPM Risk-of-Retirement and RMR processes to ensure market participants do not choose between the two to obtain financial incentives which may increase ratepayer costs. To accomplish this, the review should consider whether RMR cost recovery should include a resource's sunk capital costs ("full fixed cost of service"), as proposed in the comments of the DMM. ORA agrees with DMM's conclusion that compensation should not include a resource's full sunk capital costs less depreciation. An investigation of this issue should include the review of RMR cost of service recommended by the CPUC Staff in its prior comments. B. RMR Issues i. ORA Supports Allocation of Flexible RA value for RMR resources the ISO has added consideration of allocation of Flexible RA credits from RMR designations into the scope of phase 2. ORA agrees with CPUC Staff's comments that "(s)ince ratepayers are paying for all of the costs associated with the operation and dispatch of these resources, they should be allocated the flexible capacity attributes on the resources." If a resource has an Effective Flexible Capacity (EFC) value and could be counted towards meeting flexible capacity requirements if procured under an RA contract, then that same resource procured under an RMR contract should also count towards meeting flexible capacity requirements. Failure to count the Flexible RA value of a resource procured using ratepayer funds would result in additional procurement of unneeded flexible capacity, thereby increasing ratepayer costs. For example, Metcalf Energy Center (which is under RMR for 2018) has an EFC value ranging from 390 megawatts (MW) to 413 MW for 2018, which could be counted towards meeting Flexible Capacity Requirements. CAISO has provided no justification for why allocation of Flexible RA value for RMR resources needs to wait until 2020 for implementation. Allocation of Flexible RA value for RMR resources should be separated from the other issues scoped into phase 2 and instead, completed in time for application for 2019. ORA notes that support of allocation of Flexible RA value for RMR does not mean support for CAISO's proposal to "explore using RMR as a backstop to cover unmet flexibility capacity needs." The ISO still has not demonstrated why it seeks to expand its authority given current mechanisms in place to procure flexible capacity. Any consideration of using RMR to cover unmet flexible capacity needs requires allocation of flexible capacity attributes from RMR resources. But the opposite is not true; allocation of flexible capacity needs does not require expansion of RMR as a backstop to address flexibility needs. ii. ORA Supports Consideration of Whether RMR Condition 1 and Condition 2 Unit Types are Needed ORA continues to support investigating whether both Condition 1 and 2 unit distinctions for RMR agreements are still needed. The Draft Final Proposal notes that market uncertainty has led to generator selection of Condition 2 to ensure cost recovery, though ORA, DMM, PG&E, and CPUC have identified the economic and ratepayer benefits of Condition 1 units. CAISO, PG&E, and Calpine have recently reached an Offer of Settlement arbitrated by the FERC for the RMR agreements at the Yuba City, Feather River, and Metcalf energy centers. One of the terms of the Settlement switched the units from Condition 2 to Condition 1. ORA recommends that Phase 2 should include an analysis of the costs and benefits of RMR Conditions 1 and 2 and whether they are both necessary to ensure reliability. C. CPM Issues i. ORA Supports Expedited Review of Cost Allocation of Year-Ahead CPM to Maintain Customer Indifference Cost allocation of year-ahead CPMs is complicated by mid-year load departure issues. LSEs within an area benefitting from a year-ahead CPM should receive an adjustment to the costs they pay and the credits they receive for the CPM as load migrates between the LSEs, in order to maintain customer indifference in rates and minimize all ratepayer costs. The ISO intends to address this issue in phase 2, but load departure may accelerate through 2019, before phase 2 enhancements are expected to be in effect at the start of 2020. This issue would be compounded if resources owners seek additional retirements of natural gas power plants in 2018 and 2019. The ISO should quickly explore tariff and non-tariff modifying approaches to address this issue to provide equitable cost allocation for LSEs experiencing load shifts. If it is not possible to modify CPM in phase 1, the issue should be separated from the other issues scoped into phase 2 and completed in time for application for 2019.

SCE – As noted above, the cost allocation for load migration should be moved forward to phase 1.

Sierra Club - To focus discussion of potential reform to RMR and CPM procurement, the purpose and relationship of each mechanism and its relationship with RA should first be defined. Sierra Club supports the ISO's intention to "provide a process map showing how retirement requests will be evaluated within the overall process ... to provide an understanding of how the procurement processes interact with each other. However, this alone is insufficient. Importantly, what is the purpose of each mechanism and what is it trying to achieve? For example, to the extent RMR is a mechanism of last resort to retain needed resources that would otherwise retire for economic reasons, existing RMR terms do not reflect this purpose. Resource owners seeking an RMR designation currently have no requirement to substantiate their claims that their resource is, in fact, uneconomic and that they would otherwise retire.

Rather, current policies may incentivize generators to seek an RMR designation first, rather than as a mechanism of last resort. Accordingly, the priority for Phase 2, perhaps in an initial pre-phase, should be to define the purpose and interrelationship of each mechanism to properly inform and focus subsequent revisions to existing structures. Defining the purpose of these mechanisms early in this process will lead to a more productive and focused discussion in Phase 2.

Six Cities – The Six Cities attach the highest priority for Phase 2 to the following: • Review allowed rate of return on capital for RMR and CPM compensation (March 13, 2018 paper at 19-20) - - The stated 12.25% return on capital allowance currently in place is outdated and excessive under current capital market conditions. • Restructuring/consolidation of backstop procurement for resources at risk of retirement - - To reduce the risk of inconsistency in treatment of similarly-situated resources or in resolution of reliability needs, the Six Cities support a comprehensive review of the CPM and RMR mechanisms for backstop capacity procurement by the ISO with an objective of clarifying and rationalizing the processes. Such a comprehensive review/restructuring of the ISO's backstop procurement authority for resources at risk of retirement should include the following related topics identified as potential Phase 2 items: (i) Clarify when RMR is used versus CPM procurement (March 13, 2018 paper at 19); (ii) Explore whether RMR and ROR CPM can be merged into one backstop procurement mechanism (Id.); (iii) Consider whether both Condition 1 and 2 Units are still needed (Id. at 20); and (iv) Expand designation authority to include flexibility needs (Id. at 22).

4. Other Comments

CLECA – CLECA objects to the following items in either Phase 1 or 2: A. It is unnecessary to expand authority to use RMR or CPM for flexibility need and renewable integration because it is not a local capacity requirement nor is it necessary for renewable integration. The RA process includes a requirement to acquire system capacity, local capacity, and flexible capacity, but there is no requirement for local flexible capacity. So far there has been no indication that LSEs are not procuring enough flexible capacity for the ISO to manage flexibility needs or renewable integration. Furthermore, the ISO is in the process of addressing flexibility requirements in the Flexible Resource Adequacy Must-Offer Obligation and Day-ahead Market Enhancements initiatives. In addition, there are other mechanisms being developed to manage renewable integration such as demand response, load shift programs, increased storage, integrated storage with Solar PV, and time of use pricing changes. It is not necessary for the ISO to procure resources for this purpose via the RMR or CPM mechanisms. The ISO can reconsider this if the situation changes. B. Aligning the CPM and RMR recovery of capital cost or capital additions needs careful review and should be done after better defining the use of the two contracts. While it may make sense to have consistent terms between CPM and RMR, there may be justified differences for the treatment of capital cost recovery. For example, for the CPM associated with risk of retirement, it is not clear that existing capital costs should be able to be recovered, other than going forward fixed costs. This issue is being litigated at FERC. The RMR contract was designed to be an ongoing cost of service contract for critical units because at the formation of the CAISO, IOUs were not allowed to sign long-term contracts. Today, the limitation on long-term contracts no longer exists. Does it make sense for what should be short-term contracts to include full cost recovery of existing capacity and ongoing capital costs? Certainly, the CPM and RMR contracts should not be so lucrative that resources use them as a fallback if they fail to negotiate a bi-lateral deal.

DMM – In addition to RMR compensation, DMM's comments to FERC on the Metcalf Energy Center RMR described several other existing issues with CPM and RMR policy. DMM strongly encourages the ISO to address each of these issues in Phase 2 of the initiative: • The timeline of the RA program and the CPM process should be moved back to accommodate the actual timeline needed to make decisions about resource retirements and potential alternatives for meeting local needs. • The ISO's first option for procuring additional capacity needed to meet reliability requirements – the capacity procurement mechanism – is voluntary and can be declined by suppliers with local market power. This could undermine the capacity procurement mechanism if suppliers view RMR compensation to be more favorable than CPM compensation.

Six Cities – At the top of page 20 of the March 13, 2018 Proposal, the ISO identifies as an item under consideration for Phase 2 "Explore expanding ISO's tariff authority regarding LCR criteria as well as integration of renewable resources." The description of the topic that follows is overly general and vague and does not provide sufficient information about the nature of potential tariff revisions the ISO may wish to consider under this topic. The Six Cities recommend that the ISO either describe the topic with greater clarity and specificity or delete the topic from the list of items under consideration for Phase 2 of the initiative.

Appendix 3

RMR Resource Performance Incentive Provisions

This appendix to the straw proposal provides the performance incentive provisions that exist in the current RMR pro forma agreement.

The Monthly Option Payments defined in Article 8 of the RMR pro forma agreement are based on availability and response to dispatches, i.e., they are performance based. The paragraphs in Article 8 define the performance based payments. Article 8 is provided below.

ARTICLE 8

RATES AND CHARGES

8.1 Condition 1

When a Unit is under Condition 1, CAISO shall pay Owner each Month for each Unit the sum of:

(a) The Monthly Option Payment which shall be equal to the Monthly Availability Payment plus the Monthly Surcharge Payment, minus the sum of all Non-Performance Penalties for the Month. In no event shall (i) the Monthly Option Payment for any month be less than zero, (ii) the sum of the Monthly Availability Payments for a Contract Year exceed the Annual Fixed Revenue Requirement for the Contract Year, or (iii) the sum of the Monthly Surcharge Payments for the Contract Year exceed the Annual Capital Item Cost (as defined in Schedule B) for the Contract Year. The Monthly Availability Payment and the Monthly Surcharge Payment shall each be computed in accordance with Schedule B. The Non-Performance Penalties for the Month shall be calculated in accordance with Section 8.5;

(b) The Variable Cost Payment computed in accordance with Schedule C;

(c) One-twelfth of the Prepaid Start-up Charge as set out on Schedule D;

(d) The sum of the Start-up Adjustments calculated in accordance with Schedule D for each Start-up during the Month which was a Prepaid Start-up;

(e) The sum for all Settlement Periods in the Month of the Pre-empted Dispatch Payments and Motoring Charges calculated in accordance with Schedule E;

(f) Once the Counted MWh for the Contract Year equals the Maximum Annual MWh, the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours, or the Counted MWh for hydroelectric units for the Month equals the Maximum Monthly MWh, a payment for each subsequent Billable MWh at the rate set out on Schedule G;

(g) Once the Counted Start-ups for the Contract Year equals the Maximum Annual Start-ups, a payment for each additional Start-up calculated in accordance with Schedule G; and

(h) Charges for services Delivered from Substitute Units pursuant to Sections 5.1(c) and (d).

8.2 Condition 2

When a Unit is operating under Condition 2, CAISO shall pay Owner the sum of:

(a) The Monthly Option Payment, which shall be equal to the Monthly Availability Payment plus the Monthly Surcharge Payment, minus the sum of all Non-Performance Penalties for the Month. In no event shall (i) the Monthly Option Payment for any month be less than zero, (ii) the sum of the Monthly Availability

Payments for a Contract Year exceed the Annual Fixed Revenue Requirement for the Contract Year or (iii) the sum of the Monthly Surcharge Payments for the Contract Year exceed the Annual Capital Item Cost (as defined in Schedule B) for the Contract Year. The Monthly Availability Payment and the Monthly Surcharge Payment shall each be computed in accordance with Schedule B. The Non-Performance Penalties for the Month shall be calculated in accordance with Section 8.5.

(b) The Variable Cost Payment computed in accordance with Schedule C;

(c) The sum of all Start-up Payments for the Month until Counted Start-ups equal Maximum Annual Start-ups computed in accordance with Schedule D;

(d) The sum for all Settlement Periods in the Month of Motoring Charges calculated in accordance with Schedule E;

(e) Once the Counted MWh for the Contract Year equals the Maximum Annual MWh or the Counted Service Hours for the Contract Year equals the Maximum Annual Service Hours, a payment for each subsequent Billable MWh at the rate set out on Schedule G;

(f) Once the Counted Start-ups for the Contract Year equals the Maximum Annual Start-ups, a payment for each additional Start-up calculated in accordance with Schedule G; and

(g) Charges for services Delivered from Substitute Units pursuant to Section 5.1(c) and (d).

8.3 Determination of Billable MWh and Hybrid MWh

(a) “Billable MWh” shall be determined by application of the following rules:

(i) If a Unit under Condition 1 or Condition 2 Delivers MWh only in Nonmarket Transactions during a Settlement Period, the Billable MWh shall be the lesser of (A) the Hourly Metered Total Net Generation or (B) the Requested MWh.

(ii) If a Unit under Condition 1 delivers MWh in both Market and Nonmarket Transactions during a Settlement Period:

(A) If the Hourly Metered Total Net Generation during the Settlement Period is equal to or greater than the Requested MWh applicable to the Settlement Period, the Billable MWh shall be (1) the Requested MWh minus (2) the Hybrid MWh, but shall never be less than zero.

(B) If the Hourly Metered Total Net Generation during the Settlement Period is less than the Requested MWh applicable to the Settlement Period, the Billable MWh shall be (1) Hourly Metered Total Net Generation minus (2) the Hybrid MWh, but shall never be less than zero.

(iii) If a Unit is under Condition 2, the Billable MWh shall be the lesser of (A) the Hourly Metered Total Net Generation or (B) the sum of (1) Requested MWh and (2) the amount, if any, by which the total MWh for which Owner's bids pursuant to Section 6.1 (b) cleared the market exceeds the Requested MWh.

(b) "Hybrid MWh" shall be the sum of the MWh scheduled in Market Transactions which were substituted for Requested MWh under Section 5.2 and the MWh scheduled in Market Transactions for which CAISO issued a Dispatch Notice pursuant to Section 4.5 provided that Hybrid MWh shall never exceed the Hourly Metered Total Net Generation.

8.4 Determination of Prepaid Start-ups

Prepaid Start-ups for Condition 1 shall be the Maximum Annual Start-ups. There shall be no

Prepaid Start-ups for Condition 2.

8.5 Non-Performance Penalty

(a) If a Unit fails to comply fully with a Dispatch Notice and such failure is not due to a Force Majeure Event under this Agreement, the Unit shall be subject to a Non-Performance Penalty computed in accordance with this Section 8.5.

(b) The Non-Performance Penalty shall be calculated for each hour of the Penalty Period in which Owner is not deemed to be in full compliance with a Dispatch Notice and is not excused from performance. The Non-Performance Penalty shall be the sum of the amounts calculated for each Settlement Period in the Month by multiplying (i) the Availability Deficiency Factor for the Settlement Period by (ii) the sum of the Hourly Penalty Rate and the Hourly Surcharge Penalty Rate for the Unit as set forth on Schedule B; provided that the Non-Performance Penalty for any Month shall not exceed the sum of the Condition 1 Availability Payment and Condition 1 Surcharge Payment (for Units on Condition 1), or the sum of the Condition 2 Availability Payment and Condition 2 Surcharge Payment (for Units on Condition 2) for the Month. For purposes of this calculation:

(i) An Availability Deficiency Factor shall be calculated for each hour of the Penalty Period as one minus the number determined by dividing (a) the Delivered MWh for the hour in question by (b) The product of the Unit Availability Limit and the percentage of the hour (up to 100%) that the Unit was subject to a Dispatch Notice;

(ii) The Penalty Period shall be the 72 hour period beginning at the time Owner fails to comply fully with a Dispatch Notice, provided that if Owner in accordance with Section 7.2(a) had scheduled an outage to begin during the 72 hour period, the Penalty Period will terminate at the time the outage was scheduled to begin.

(iii) The Unit Availability Limit shall be the Unit Availability Limit as it existed at the time CAISO issued the Dispatch Notice with which Owner failed to comply but reduced to eliminate the effect of any Force Majeure Event affecting deliveries during the Penalty Period.

(c) For purposes of this Section 8.5 and Section 4.9(a)(i), a Unit shall be deemed to be in full compliance with a Dispatch Notice if the Unit Delivers (i) at least 97 percent of the Requested MW or (ii) not more than 2 MW less than the Requested MW.

8.6 Long-term Planned Outage Adjustment

Not later than 60 days after the end of each Contract Year, Owner shall submit to CAISO a statement showing the Long-term Planned Outage Adjustment for the Contract Year. The Long-term Planned Outage Adjustment shall equal (a) the Hourly Availability Charge plus each Hourly Capital Item Charge, as shown in Schedule B, multiplied by (b) the difference, if positive, of (i) the hours scheduled for performance of Long-term Planned Outages minus (ii) the actual hours spent performing Long-term Planned Outages during the Contract Year. Owner shall credit any Long-term Planned Outage Adjustment on the next invoice or, if this Agreement has terminated, shall pay any Long-term Planned Outage Adjustment to the CAISO upon submission of the Final Invoice.

Section 6 of Schedule B of the RMR pro forma agreement is provided below.

6. <u>Target Available Hours</u>
A Unit's Target Available Hours for each Contract Year are calculated in accordance with the Equation B-10 below:

Equation B-10

Target Available Hours (TAH) = Hours in the Calendar Year – (Average Other Outage Hours + Long-Term Planned Outage Hours)

Average Other Outage Hours means the average annual Other Outage Hours for the Unit during the 60-month period ending June 30 of the previous calendar year.

Long-term Planned Outage Hours means the Long-term Planned Outage Hours for the Contract Year scheduled with CAISO pursuant to Section 7.2(a). For periods prior to December 31, 1998, Other Outage Hours shall exclude a planned interruption, in whole or in part, in the electrical output of a Unit to permit Owner to perform a major equipment overhaul or inspection or for new construction work, but only if the outage lasted 21 or more consecutive days.

Long-term Planned Outage Hours scheduled for a Contract Year shall be subject to the Long-term Scheduled Outage Adjustment pursuant to Section 8.6 of the Agreement.

The Average Other Outage Hours, Long-term Planned Outage Hours and Target Available Hours for each Unit for the Contract Year are shown in Table B-5 below:

Table B-5			
Unit	Average Other Outage Hours	Long-term Planned Outage Hours	TAH

For the purposes of calculating Target Available Hours for the Contract Year ending December 31, 1999, (a) Average Other Outage Hours shall be calculated using the average annual Other Outage Hours for the Unit during the 60-month period ending December 31, 1998, and (b) Long-term Planned Outage Hours shall be calculated using the hours scheduled for performing Long-term Planned Outages as if the Agreement had become effective on January 1, 1999.