Submitted Stakeholder Written Comments

RMR and CPM

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

CalCCA - The ISO should provide the information to the interested parties first (owner/operator) to ensure information is correct prior to releasing to the public. As corrections and additions are published, a market message should be sent out alerting the market and providing the link to view the updates.

Calpine supports pro-active resource-owner communications with the ISO, particularly with respect to asset disposition. Calpine will continue to keep the ISO informed whenever the ongoing near-term operation of a generation resource is in question. However, it is unlikely that final decisions on the disposition of the hard assets (e.g., "retirement") would be made prior to such notifications. Therefore, such notifications may indicate that the asset is being made "unavailable for dispatch" and may be seeking retirement, decommissioning, mothballing, repowering, replacement, or other options. Calpine will not object if the ISO releases the notice of potential unavailability publicly, but believes that any prospective plans (e.g., redevelopment, repowering, decommissioning) should be held confidential until the resource-owner decides to make them public (e.g., by filing at the CEC). We do note, however, that multi-year forward contracting requirements may reduce the frequency of these notifications as resources will know, much further in advance, their contractual status.

CPUC - Staff appreciates that the ISO is providing more transparency regarding resource owner requests for retirements. In July, the ISO posted a list of resources seeking to retire and/or asking to be studied for reliability. This level of transparency allows all stakeholders to see which generators are requesting to be studied and which generators are actually requesting to retire. Staff requests that the ISO alert market participants when it receives additional requests.

NRG does not oppose what the ISO has implemented on this issue.

ORA - ORA supports the ISO's creation of the Announced Retirement and Mothball List. The list will allow market and regulatory stakeholders to plan for the changing RA landscape of resources and to devise strategies to adjust for or even preclude ISO backstop. At the July 11 meeting, PG&E expressed concern that the ISO does not plan to send out notice to stakeholders when the list is updated or revised. ORA shares this concern, since most stakeholders may not make a habit of checking the list regularly and could be unaware of new retirements. ORA recommends that the ISO publish a market notice immediately following any modification to the list to ensure that stakeholders promptly learn of the changes and can plan accordingly, as intended by the creation of the list in the first place.

b. Clarify when RMR procurement is used versus CPM procurement

Calpine believes that RMR should be a last-gasp reliability tool. It should be used when unforeseen circumstances arise that drive to a long term reliability need for a resource. However, significant reforms of the RA timeline and degree of forward contracting are necessary to achieve this vision as a last-gasp tool. The current timeline for resource-owner decision-making has forced the ISO to appropriately use RMR well in advance of decisions made in the RA and CPM processes (note the recent authorizations by the ISO Board for Moorpark NRG assets). At least three things are needed to make RMR a true backstop. First, a longer runway for decision-making must be in place. Calpine would support independent action by the ISO (if necessary) to adjust annual RA timelines to provide a reasonable runway for CPM to operate as designed. We would support either our initial proposal to move forward the RA "showings" to June, or the ISO's proposal submitted to the CPUC to leave "showings" in October, but slide the start-date of the compliance to April. In addition to moving the process timeline, a multi-year forward requirement would assist in creating more efficient retirement and decommissioning process. Second, there must be a Central Buyer established to procure capacity that is needed, including sub-area local requirements, but not contracted. Calpine believes that as the reliability agent, the ISO must be the buyer of last resort and it is inefficient and unnecessary to have another entity assume this role. Third, as described in our presentation of May 30, the ISO should consider changes to the Competitive Solicitation Process to facilitate efficient procurement with the ISO as the Central Buyer. These three elements would position CPM/CSP as the primary backstop to bilateral transactions and RMR as merely a circuit-breaker when all else fails. Each of these elements is currently under consideration by the CPUC, but could be implemented squarely within the four corners of the ISO tariff. The ISO appears to have designed this stakeholder initiative schedule to allow for the incorporation of any CPUC decisions in its final design proposal (currently scheduled to be circulated in early 2019). However, we encourage the ISO to consider independent and autonomous action to implement these provisions, as necessary.

CPUC - <u>Combine its current RMR mechanism with its CPM mechanism so as to simplify the ISOs backstop role to one mechanism -</u> The current Section 43A of the CAISO's CPM tariff provides the ISO the authority to procure resources under the following situation: 1) Insufficient Local Capacity Area Resources in an annual or monthly RA plan, 2) Collective deficiency in local capacity area resources, 3) Insufficient RA resources in an LSE's annual or monthly RA plan, 4) A CPM Significant Event, 5) A reliability or operation need for Exceptional Dispatch CPM, 6) Capacity at ROR within the current RA compliance year that will be need for reliability by the end of the calendar year following the current RA compliance year, and 7) A cumulative deficiency in the total flexible RA capacity included in the annual or monthly flexible RA capacity plans, or in a flexible capacity category in the monthly flexible RA capacity plans. Staff believes that the authority listed above provides the ISO the same authority to backstop for RMR resources. The main difference between the two mechanisms is that CPM is voluntary and RMR is mandatory with regards to accepting a payment. <u>Make CPM mandatory for resources that do not bid into the CSP but are needed for reliability</u> - Staff proposes that the ISO change its current CPM tariff to be a mandatory designation for resources that do not participate in the CSP but are needed for reliability. Currently, if a resource does not bid into to the CSP, a bid at the soft offer cap will automatically be submitted for them. The resource owner can decline this designation/payment. However, if this designation is an exceptional dispatch the resource still has to respond to the dispatch. From an operational standpoint, Staff interprets this to be mandatory. From a compensation standpoint, it appears to be voluntary. Staff proposes that all types of CPM, including exceptional dispatch, be made mandatory from a compensation standpoint. This could be achieved by allowing resources to be paid above the soft offer cap if their GFFC exceed the soft offer cap. Generators would be required to submit these costs to FERC for approval the same way they do today. However, they would be limited to only going forward fixed costs and provisions for needed and justified capital additions. <u>Identify a clear timeline that would allow resources to be approved and designated as RMR after the bilateral RA process and the CPM process have concluded</u> –-The ISO continues to assert that RMR should be the last resort for procurement because it is a mandatory designation. In its current straw proposal the ISO plans to expand RMR authority to include CPM ROR. Therefore, RMR will be the sole vehicle to retain resources that are needed for reliability and at risk of retiring. RMR currently is the sole vehicle to retain resources that are seeking to retire but are needed for reliability. Since RMR should be the last resort, then it is critical that the RMR designation be made after the annual bilateral process concludes. This is not how the current RMR process is implemented today. RMR designations currently front run the bilateral process and will continue to unless the current tariff is changed to not allow RMR designations to be made at any time. As discussed above, one way to ensure that RMR designations do not front run the bilateral process is to merge CPM and RMR authority into the current CPM process, which is conducted after the bilateral processes has concluded. Another way of doing this would be to establish a timeline for RMR approvals and designations to be made following the conclusion of the ISO's annual CPM process. If a resource refuses a CPM designation the ISO could then designate the resource for the coming year and allow it to recover is GFFC through a FERC approved filing. In addition, the current straw proposal does not provide a timeline or a window that would follow the conclusion of the bilateral procurement process and the CPM process; therefore, the current straw proposal fails at mitigating FERC stated concerns of front running. Staff request that if the ISO plans to continue to use RMR both as a vehicle to procure needed resources that are planning to retire or at risk of retiring, it needs to establish an approval and designation process that occurs only after the bilateral procurement process has concluded. <u>Establish a timeline for resources seeking to retire to submit request so that they can be assessed for need and potential CPM or RMR designations</u> - Staff understands that generators are requesting information on whether they are needed for the coming year so that they can make retirement decisions. Therefore, Staff proposes that the ISO require generators to submit retirement requests by a certain date each year. These requests would be incorporated into the annual local and flex studies so they could be studied within a stakeholder process. In order for this to work, retirement requests for the coming compliance year would need to be made prior to February 15 (or the latest possible date for the ISO to incorporate into annual Local and Flexible Capacity Requirement Studies). Providing the ISO and market participants with more time to study planned retirements would in turn provide generators with more certainty regarding retirement decisions. If the retirement notice is not submitted in a timely fashion, then the need for the resource would not be assessed in the planning process.

DMM - All ISOs need mandatory backstop procurement authority. Backstop procurement serves two functions: reliability and market power mitigation. An ISO must be able to procure and compensate capacity needed to ensure local and system reliability. Furthermore, since capacity needed to ensure reliability has market power, such compensation must be subject to mitigation to ensure just and reasonable rates. In the ISO, backstop capacity procurement is one piece of the larger capacity procurement framework, which also includes RA. A coordinated effort between the ISO, CPUC and stakeholders to reform RA is already underway in CPUC proceeding R.17-09-020. DMM appreciates the need for comprehensive RA/CPM/RMR reform. However, comprehensive reform will take some time -- perhaps at least 1 to 2 years. The ISO's RMR/CPM Review initiative is an intermediate step to broader reforms of the RA framework. Therefore, DMM believes the ISO should move forward expeditiously to develop needed reforms in its annual backstop procurement on a more accelerated timeline than will be required for broader changes in California's RA process DMM recommends that the ISO act expeditiously in this initiative to consolidate annual backstop procurement into a single mechanism. Combining RMR and CPM into one annual backstop mechanism could improve the incentives for generation owners to participate in the RA process and be an important initial step in improving the cost effectiveness and efficiency of the ISO and CPUC's capacity procurement and compensation processes. Ideally, the ISO should be prepared to file and implement reforms that address the fundamental flaws with the CPM/RMR mechanisms if needed in time for backstop procurement designated for 2019. Aside from the compensation changes to CPM described by DMM in these comments, modifications to the timing of annual CPMs will need to be considered. A new timeline will need to be worked out for studying and awarding CPM contracts. DMM believes it would be better to address those issues in conjunction with reforms to the broader RA process. Immediately making the changes outlined above could improve the annual backstop procurement mechanism and increase participation in the RA process while the ISO works with the CPUC on broader RA reforms.

NRG - The ISO's rationale for retaining both RMR (as the ROR mechanism) and CPM (as a short-term backstop mechanism) seems appropriate. NRG believes that the ISO underestimates the complexity involved in turning the RMR contract into a means to take RA-equivalent service from units at ROR.

PG&E supports the ISO position that only units which have given their 90-day notice for termination of the PGA should be studied for designation and be eligible to receive an RMR from the ISO, if warranted. This clarification represents a significant improvement to the process, in that it reduces the ability for a resource owner to "test the waters" to see if a unit may be eligible to receive an RMR, while preserving its optionality to receive an RA contract or CPM (if an RMR is not available). As part of this proposal, PG&E requests that the ISO further clarify the anticipated timeline for the fall designation window for units either currently on an RMR agreement that may be eligible for renewal, or for units that will be designated starting January 1, based on a retirement in an upcoming calendar year. Currently, the ISO presents any such RMR renewals or recommendations for new designations to its Board in the fall, allowing at least 60 days between the submission by the resource owner of the RMR agreement at FERC and the requested date for the RMR rate schedule change to go into effect. This has historically resulted in the ISO bringing most RMR agreements to its Board no later than the end of October, which coincidentally aligns with the end of the CPUC RA contract window for the upcoming RA year. For units that will now submit a PGA termination letter at least 90 days prior to a January 1 retirement (seeking a calendar year RMR for the full year), this notification can occur no later than October 1, which is prior to the final close of the RA contract window. A notification at this date would compel CAISO staff to study, recommend, and receive Board approval to designate an RMR for a needed unit within less than 30 days, in order to provide the 60 day FERC filing window. PG&E notes that the ISO Board only meets approximately every six to eight weeks, and does not always have a scheduled meeting during the available fall time period, meaning an emergency meeting might have to be scheduled to handle any such RMR renewals or new designations, if the PGA termination were received close to the 90-day deadline. PG&E encourages the ISO to provide additional information in the next Straw Proposal in order to clarify these timelines.

SCE - Given SCE's observation in the "Other" comments section that resources may show preference for an annual CPM it would be prudent for the ISO to eliminate any annual CPM. This would eliminate any incentive for resources to inappropriately seek an annual CPM when they would be more suited for an RMR. This will allow the ISO to use the RMR as intended and not compromise the RA mechanism.

The Six Cities support the ISO's proposal to make RMR designations only for needed resources that have notified the ISO of plans for retirement (Straw Proposal at 17 – 18).

WPTF believes that the ISO has done a good job at explaining the functional differences between RMR and CPM. The ISO has explained why, how, and when an RMR designation will be used versus a CPM designation. WPTF remains less sure on the desired use for each mechanism. WPTF asks that the ISO could more concretely articulate which type of resources should use each mechanism in order to allow the policy to be refined in a manner that best suit the ISO's desired intent. WPTF does not see a clear difference between the resources that should use the RMR or CPM in the ISO's current proposal and this is leading to some significant concern over requiring a MOO and RAAIM penalties for RMR resources. Because of the difference in resources that may be given an RMR designation, WPTF is having trouble supporting any of the ISO's proposals that are one size fits all.

c. Explore whether Risk of Retirement CPM and RMR procurement can be merged into one procurement mechanism

Calpine supports the elimination of CPM ROR, and the retention of RMR.

CPUC - Staff strongly opposes expanding RMR to year two and year three. The CPUC's current RA proceeding, R.17-09-052, is developing a local multi-year framework that will likely help to provide local generators with long term contacts to provide revenue certainty into the future. Staff has serious concerns that if RMR or CPM authority is extended to years two and three that this will expand the current front running issue that is occurring in the one-year framework. The ISO's current RMR tariff already allows for a resource seeking retirement to be designated (as we saw with the Calpine units). What the ISO is proposing here will result in front running of the future multi-year bilateral construct that is currently be developed at the CPUC. Staff urges the ISO to remove any backstop authority for multi-year products at this time. Not doing so will only result in the ISO further front running the competitive bilateral RA market.

NRG - As aptly noted by Constellation's representative at the July 11 meeting, retaining two mechanisms creates the possibility for market participants to arbitrage the two mechanisms absent clear protocols indicating which mechanism is to be used for which situation. While it would ideal to have a single ISO backstop mechanism, not two, the ISO has made a credible case for retaining two backstop mechanisms due to the different situations in which they would be applied. The rules for which mechanism should be used in which circumstance must be clearly specified and adhered to.

ORA - The Straw Proposal seeks to remove CPM tariff language for capacity at ROR but needed for reliability and to revise the RMR tariff to add the authority to designate a resource based on need in future years. Specifically, under the current CPM tariff, if a resource is at ROR the ISO may grant the resource a CPM designation for the following year, when its capacity is not needed, to allow it to offer its RA capacity in the year beyond the following year when the ISO forecasts it will be needed for reliability. The Straw Proposal seeks to add "that same authority to 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." ORA notes that the Straw Proposal explores a bridge length for a resource to show up in "year three," two full years under RMR before it is needed. The current CPM tariff does not include such a provision. ORA opposes this change for the following reasons. In the current RA Rulemaking (R.) 17-09-020, the CPUC intends to implement a multi-year RA contracting requirement that would provide more resource owners with multi-year contracts. The requirement would be for at least three years, which would require forecasts three years forward. In that proceeding, the ISO has proposed to identify essential reliability resources needed to meet reliability requirements which will inform multi-year procurement. These upcoming changes to procuring RA will provide resources needed for reliability the opportunity for multi-year contracts. Extending RMR to multiple years could motivate some resource owners to seek lucrative multi-year RMR contracts rather than offer competitive multi-year RA bids in LSE solicitations. Similar to the ISO's 2017 proposal to modify the design of the ROR CPM, the ISO's proposal to extend RMR would allow resource owners to learn whether or not their resources are needed prior to seeking an RA contract in competitive LSE solicitations. The RMR process is not constrained by any window of opportunity for resources to be considered for or granted an RMR agreement. If the ISO notifies a generator that it is needed for reliability before or during LSE procurement of RA contracts, then the generator has market knowledge that it will receive an RMR rate and could provide bids similar to what it would receive through the RMR contract. To minimize ratepayer costs, ORA supports procurement of RA contracts through competitive solicitations issued by LSEs rather than costly backstop procurement through CPM and RMR designations. In regards to the ISO's proposed ROR CPM revisions, FERC found that "CAISO has not adequately demonstrated that its proposal addresses the front-running concerns raised by protestors and that the proposal will avoid potentially deleterious effects on the competitiveness of capacity procurement under CPUC's resource adequacy program." Those concerns apply similarly to the ISO's proposal to extend RMR. Additionally, the Straw Proposal's suggested three-year RMR designation is a major departure from the current ROR CPM tariff, which only considers a two-year designation and represents significant costs to ratepayers. Under this proposal, the ISO could grant a resource an RMR contract if CAISO forecasts that it is not needed in the next year or following year, but needed three years away. Under this proposal, a resource may notify the ISO that it intends to retire on August 2018. The ISO would perform a study and may find that the resource's capacity is not needed until January 2021. The ISO could then grant the resource an RMR contract for the full years of 2019 and

2020 on the assumption that the resource will be procured in 2021 if the need is realized. Ratepayers would pay the costs for the two years during which the capacity is not needed. However, a resource solution could arise in a short time frame that would remove the need for the resource in 2021. For example, PG&E's proposed transmission solutions in the South Bay/Moss Landing sub-area show how quickly some solutions can be deployed to reduce local needs. PG&E's proposed projects were approved by the ISO Board in March 2018 and will be in place beginning in 2019. The ISO's proposal to extend RMR could greatly increase costs to ratepayers. For these reasons, the ISO should remove its proposal to extend RMR.

PG&E does not support expanding the ISO's authority under the tariff to issue RMR designations for forecasted needs in "year two" or "year three." The ISO's proposal may skew generator incentives in contracting because the generator will know whether it has received an RMR designation prior to the bilateral market operating. This could lead to resources front running the bilateral RA procurement processes and result in higher RA costs. In addition, this would prevent the ISO from considering cost-effective transmission alternatives that could be implemented immediately to honor the unit's explicit request to cease operation.

SCE feels it may be more effective to merge the two mechanisms. This would prevent the risk of inappropriate use of one mechanism over the other.

The Six Cities support the ISO's proposal to delete from the CPM tariff provisions ISO authority to offer a CPM designation for a resource at ROR and add to the RMR tariff provisions authority for the ISO to make RMR designations for needs anticipated during up to three years (Straw Proposal at 17 – 20).

d. <u>Evaluate compensation paid for RMR and CPM services</u>

Calpine - The ISO proposes several changes to the compensation for CPM. As a first principle, Calpine believes that resources required for reliability, but not otherwise contracted must have, pursuant to foundational court decisions on regulatory economics (*Hope, et. al.)* a reasonable opportunity to recover their costs-of-service *including* a return of (depreciation), and on (rate of return), its investment. In this regard, the CPUC Staff has raised a question whether CPM should allow for the filing of full costs-of-service when the resource-owner does not believe that the CPM soft cap provides sufficient compensation. In this regard, Calpine supports the existing tariff (that FERC has found to be just and reasonable) which provides the opportunity (but not the obligation) to seek "Schedule F" cost recovery. However, we agree with the CPUC Staff that if in fact, an entity seeks "Schedule F" costs (Section 43A.4.1.1.1), the ISO should reconsider the provision allowing the entity to retain market revenues as well as such full cost of service payments. To address this issue the ISO proposes to limit the cost recovery for all types of CPM (and CSP bids) to GFFC plus 20 percent. The ISO claims that this 20 percent adder should be sufficient to perform long-term maintenance or make environmental upgrades. We disagree. These "sufficiency" assertions are unfounded and unsupported by data or analysis. Calpine does not support this proposal, as it does not allow for a reasonable opportunity to recover significant major maintenance (such as the $20 MM that forced our Metcalf facility to seek alternative solutions) and, in direct conflict with *Hope*, to recover the full cost of service. Rather, Calpine proposes that the resource owner should retain the right to file its full cost-of-service at FERC, but if they do seek recovery of costs above the soft cap, that any market revenues, must be returned to the ISO. This makes the CPM compensation similar to that of an RMR condition 2 unit. Finally, the ISO proposes (at p17, section 6) that if a resource declines a CPM designation, unless told differently, it will assume the unit is available and it will use Exceptional Dispatch to commit that unit if a reliability need arises rather than considering RMR. An RMR would only be used if the unit owner submits a "retirement letter". Calpine views this proposal as an unjust and unreasonable free call-option. That is, the ISO is relying on a unit to meet a defined reliability need (as proven by the CPM offer) but does not compensate the unit *a priori* for providing that service. Calpine proposes that if the ISO affirmatively intends to use ED to meet otherwise unmet reliability needs that it adopt several complementary changes to yield a just and reasonable market structure: (1) that the uncontracted portion of the unit has no must offer obligation even though the ISO deems the unit as "available"; (2) that the energy bids of that unit are *not subject to local market power mitigation* (bid caps still apply); (3) if dispatched, the unmitigated bids are allowed to set the LMP and (4) if dispatched, the ISO would be obligated to compensate that resource at CPM or its FERC-filed rates.

CPUC - <u>Changing the Cost Compensation for CPM Designations Requesting Payment above the Soft Offer Cap</u> – The ISO proposes to change the cost compensation for CPM bids above the soft offer cap. The current tariff allows generators to file for compensation above the soft offer cap using the current RMR pro forma which allows for total cost recovery (AFRR) and retention of market revenues. In its straw proposal, the ISO proposes to change the methodology to be based only on GFFC plus a 20% adder and retention of market revenues earned. Generators would have to file with FERC for cost recovery. Staff appreciates the ISO attempting to address this costs compensation error. Eliminating the ability for a generating to receive total cost compensation (sunk and GFFC) and retention of market revenues is a step in the right direction. However, staff still remains concerned that the compensation is too high. Staff recommends that the 20% adder be removed from the cost compensation calculation, given that generators retain market revenues and this provides an opportunity for sunk cost recovery, to the extent that the resource is not fully depreciated. <u>Cost Compensation for RMR Designations</u> **-** Staff does not support the ISO's proposal to retain the current cost compensation for RMR resources. The cost compensation is a key flaw in the mechanism that is incentivizing generators to choose the RMR process over a bilateral RA process. If the cost compensation continues to be full cost of service with no parameters around what can include (such as asset life limits) then resources will continue to use this mechanism over the bilateral process. Setting the right cost compensation is critical to addressing and resolving the issues that gave rise to the RMR designations that occurred last year. If the ISO wishes to utilize RMR as a vehicle to procure resources needed for reliability, then it should change the cost compensation from full cost recovery (AFRR) to GFFC plus provisions for any needed capital additions, to the extent not already including in GFFC. Staff believes this change would dis-incentivize generators from using the RMR mechanism to get higher compensation then they could through the bilateral procurement process and/or through the CPM process.

DMM - Annual CPM and RMR currently have different compensation structures and terms. Differences between CPM and RMR compensation and the voluntary nature of CPM have enabled owners of resources with market power to choose the annual backstop procurement mechanism that is most favorable to them. Recently some resource owners have favored RMR over CPM. Enabling suppliers to hold out for higher compensation undermines the CPM process, and by extension, the RA market. Compensation for backstop procurement of resources with market power should limit the potential for a resource to receive more profit than it would earn from competing in competitive markets. Paying a resource more than it would receive in a competitive market undermines RA processes and rewards (instead of mitigates) market power. GFFC plus a reasonable net profit would provide fair compensation to resources contracted for backstop capacity. If a unit needed for reliability would truly retire or mothball if not contracted by the ISO, then compensating the unit based on its GFFC plus any additional net profit would be more profitable for the unit than if it was actually retired or mothballed. GFFC-based compensation also avoids market distortions that may incent resources to seek a backstop capacity contract rather than participating in the RA process. Two approaches for GFFC-based compensation warrant consideration: (1) Compensate resources GFFC plus a reasonable fixed profit and credit net market revenues back to ratepayers; or (2) Compensate a resource at its GFFC and allow it to keep net market revenues. Current RMR compensation is fundamentally flawed and should be replaced with GFFC-based compensation under a single annual backstop procurement framework. RMR Condition 2 compensation is based on a resource's AFRR. Paying AFRR constitutes compensating a resource with market power for sunk costs and therefore sends an inefficient investment signal for longer term substitutes. Specifically, paying a required resource based on AFRR creates the incentive to build new supply or transmission capacity whose annualized costs would be greater than the existing resource's GFFC but less than the existing resource's AFRR. Investing in the new capacity would be inefficient relative to only incurring the GFFC of the existing resource. DMM provided an example of how providing compensation based on AFFR would encourage uneconomic and inefficient investments in alternatives using approximate values for AFRR and GFFC for the Metcalf Energy Center, which received an RMR designation for 2018 (*Motion to Intervene and Protest of the Department of Market Monitoring of the California Independent System Operator*, ER-641-000, February 2, 2018, pp. 10-11). Compensating RMR Condition 2 based on AFRR is also unjust for consumers, who pay the full AFRR but incur limited opportunity for market revenue crediting due to restrictions on dispatch. RMR Condition 1 compensation is also flawed. There is no methodology or even principles upon which RMR condition 1 compensation is determined. Compensation must be negotiated or litigated on a case-by-case basis. Annual CPM provisions also have shortcomings. But several changes could be made to improve CPM and reduce or eliminate opportunities for resource owners to choose between CPM and RMR compensation. DMM recommends that the ISO consider the following set of potential enhancements to annual CPM that could facilitate the elimination of RMR as a secondary annual backstop mechanism: (1) Make CPM acceptance mandatory; (2) Make targeted changes to the CPM compensation structure; (3) Grant limited exceptions to the all hours MOO. Making CPM acceptance mandatory largely eliminates the need for RMR. The ISO proposes to change the CPM pricing formula used for resources that file at FERC for a CPM price above the CPM soft-offer cap price. CPM pricing in these instances would change from

AFRR to GFFC plus a 20% adder. This change in compensation would be an improvement. However, under this proposed framework, units would keep all net market revenues in addition to fixed cost payments received from the ISO. As noted above, DMM believes compensation under a single annual backstop procurement mechanism should be based on GFFC plus a reasonable net profit. The current proposal to guarantee resources a profit of 20% of GFFC while also allowing these resources to keep net market revenues may be excessive. Furthermore, when the current CPM soft-offer cap is paid to a resource for all 12 months of an annual CPM, this compensation is likely to significantly exceed the annual GFFC of many resources. Therefore, as part of this initiative, the ISO should reconsider the soft-offer cap price for annual CPMs. Additional changes could be made to CPM contracts that compensate resources for multi-year maintenance or environmental retrofits, if those items are deemed necessary over the period the unit is needed for reliability. There is a tradeoff between paying for capital expenditures and keeping a resource running only as long as it is needed for reliability. A resource receiving a CPM designation may only be needed for reliability during a small fraction of the CPM designation time period. However, if the resource was to regularly offer in the market and get dispatched it could require large capital expenditures to operate reliably. Examples of these types of resources are older resources like those for which RMR condition 2 was originally intended, or non-economic units with minimal remaining life. A limited exception to the CPM MOO can reduce procurement cost, while still addressing a specific reliability need. In many cases, easing the MOO will be more cost effective than having the unit undergo major maintenance when it is only projected to be needed for 1-2 years.

NRG - As NRG understand, the ISO has proposed to retain a full cost-of-service (COS) rate and crediting back of net market revenues for the RMR contract (assuming Condition 2 as the default), which NRG supports. (NRG does not support the proposal for a full-time *cost-based* offer obligation for RMR units, as noted elsewhere in these comments.) The ISO has also proposed to retain the option for Condition 1, which would pay a portion of the COS rate but allow the market participant to keep all net market revenues; NRG also supports this. With regards to CPM compensation, the ISO has proposed that if a unit required compensation above the soft offer cap ($6.31/kW-month), it could file at FERC for such a rate but would be limited to recovering its GFFC plus a 20% adder (mirroring how the ISO determines the soft-offer cap using a duct-fired CCGT). Under the ISO's proposal, a unit whose compensation is limited to its GFFC plus 20% would be able to retain net market revenues. The quantity of the CPM designation must factor into any consideration of whether the ISO's proposal is reasonable. The ISO has the authority to issue a CPM designation to a generating unit for a quantity of capacity that could be as small as the unit's minimum load amount. In that case, the CPM unit may require a per-MW level of cost support for the designated CPM amount that is higher than either the per-MW rate that would be set by the unit's GFFC or even by the unit's full COS. Perhaps the ISO's presumption is that if the unit requires a level of cost support that requires the owner to file at FERC, such a unit should be put under an RMR contract, in which case the discussion about limiting cost recovery to the GFFC rate is moot. In any case, NRG requests that the ISO clarify its proposal by discussing how the designation quantity factors into this issue.

SCE – SCE recognizes both the RMR and CPM mechanisms to be explicitly reliability mechanisms. The goal of a reliability mechanism is to assure the ISO that its need will be met when the resource is called upon. As such, a resource's performance should be measured based on its availability. The resource should not hinder any ISO dispatch through either not following instruction or self-scheduling or any other behavior. As a general matter, the CPM and RMR mechanisms developed to address annual reliability needs should be established in a manner that does not provide incentive to seek out such a mechanism over an RA contract while at the same time providing reasonable revenue to such resources so as not to operate at a loss, including not only energy costs but investment costs as well. Since the resource is being used effectively to provide the same services that RA would provide, the RMR and CPM products should have sufficient incentives in them to provide the necessary reliability service. Consequently, a resource's penalty for non-performance should be commensurate with the reliability award. If the ISO sets a penalty too high, a resource could be bankrupted by getting penalized. However, if the ISO sets a penalty too low, a resource can collect the award and absorb the penalty rather than respond to dispatch. In either case, the ISO's reliability need is not met and unnecessarily incurs costs for ratepayers. Logically, the appropriate penalty for non-performance in any reliability mechanism should be set close to or equal to the award. Thus, a claw back of all revenues is an appropriate penalty for a non-performing resource. Finally, since these are reliability mechanisms, the resource costs should be appropriately covered and no market rents should be retained. Under RMR, a resource is getting its cost of service payment and is an annual contract. On the other hand, the CPM designation, the duration can be monthly or annual. While SCE does not object to the current CPM payment structure for CPM issuances with a 30 to 90 day duration, the use of this mechanism for 12 month issuances, is not logical as such issuances are primarily substitutions for RA failures. As such, the 12 month CPM issuance should either be folded into the RMR structure or be priced identical to the RMR structure. That is, unlike the current CPM, where a resource can demonstrate its costs at the FERC, or resort to the ISO offer of GFFC+20%, the 12 month CPM would be a cost of service including a rate of return with forfeiture of the market rents consistent with the RMR structure. Herein lies the issue of commensurate compensation. If a resource is only awarded a monthly CPM designation, this is not an assurance of a long-term contract. The resource has to shoulder risk for a larger proportion of a year if it only receives a monthly CPM. Allowing the resource to be compensated higher is reasonable since there should not be any long term distortions from a short term contract. Thus, GFFC+20% and retention of energy rents is acceptable only for monthly CPM awards. However, an annual CPM designation eliminates the market risk a resource has to face by covering the costs of the resource for the entire year. To have two different contracts of the same duration, annual CPM and annual RMR, be compensated differently is an invitation for resources to show preference for the contract with higher compensation. In this case, the annual CPM, with its allowance of energy rent retention, is potentially providing a better return than the RMR. The only option to make the annual CPM comparable to the annual RMR, is to have the same energy rent claw back and the same payments. In sum, the problem with the ISO proposal is not with the monthly CPM, which is not comparable to the RMR. The problem is with the annual CPM. The annual designation bears similar risk to the RMR due to its similar duration, and if allowed to have a better compensation, through energy rent retention, will be the award of choice for resources. Not only will this compromise the ability of the ISO to use the RMR appropriately, but it will also compromise the RA mechanism by encouraging resources to attempt to secure an annual CPM designation over all other participation. The compensation for annual CPM and annual RMR should be set such that resources do not show preference for one over the other. Again, the monthly CPM is not the problem in the proposal. It is the same duration contract, the annual CPM, which creates a conflict with the annual RMR. Since both these mechanisms are explicitly for reliability, the compensations should also be similar. The penalties should also be consistently applied between the mechanisms. Thus, while RAAIM may not be directly applicable on RMR, the non-performance penalty should be RAAIM-like. If the ISO cannot apply an appropriate penalty on RMR, it should not, in turn, expect any reasonable service from an RMR unit. If the two mechanisms remain unmerged, the ISO should, at least, cap the CPM compensation (GFFC+20% adder) at cost of service, similar to RMR. This will ensure parity between the two mechanisms. Finally, the ISO should allow sufficient robustness, such that future changes in market design are easily incorporated and loopholes are considered. An example of future market design changes is the ongoing stakeholder initiative proposing elimination of RUC. CPM resources should not be allowed to retain market revenues, whether through a $0 bid and $0 compensation in RUC or through revenue claw back if RUC is eliminated. On the other hand, an example of a loophole would be a RMR resource bidding below cost to get committed in the market and then collecting BCR. BCR has an adder above cost that the resource could then collect and retain. In sum, both CPM and RMR should have consistent compensation that does not allow market revenue retention, and consistent non-performance penalties, with non-performance determination solely based on lack of resource availability. Procurement timing – SCE is concerned that late procurement of RMR can cause conflicts with annual RA showings. SCE urges the ISO to holistically consider the RA process when determining the process timelines for the RMR and CPM mechanisms. RMR decisions should be made well before or after the RA process so that LSEs can appropriately account for RMR resources in their procurement activities. Efficient dispatch – Given that the reliability resources are procured at cost of service, the ISO should make every effort to avoid unnecessary costs. This is especially critical for ULRs, but in general is appropriate for all resources. This includes recognizing the limitation of the ISO optimization to make commitment decisions beyond 24 hours and mitigating unnecessary cycling of units when it may be more efficient to keep them committed between days.

The Six Cities support the ISO's proposals to revise the CPM pricing formula for resources that file at FERC for a CPM price above the CPM soft-offer cap to base compensation on the GFFCs of the resource using the same cost categories and same cost adder used for the CPM reference unit and allowing the resource to keep market revenues earned (Straw Proposal at 17, 19).

RMR

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

Calpine still sees no need for these piecemeal changes. Nonetheless, we appreciate the ISO's pledge that the ISO's unilateral and interim termination provision will not be a part of the changes to the pro-forma contract submitted at the conclusion of this initiative.

NRG does not oppose the ISO modifying the *pro forma* RMR contract to revise the termination provisions to enable the ISO to implement the *pro forma* agreement following the current stakeholder process, the Board's approval of the new *pro forma* and, most importantly, FERC's approval of the revised *pro forma*. NRG appreciates the ISO clarifying that the revised termination provisions are temporary and will not apply to RMR contracts that may be filed prior to the conclusion of the stakeholder process.

f. Update certain terms of pro forma RMR agreement

i. Remove AS bid insufficiency test and revise dispatch provisions to align with current market design

Calpine believes that any modification to AS bid insufficiency tests, or more generally, modifications to Section 4.1 ("CAISO's Rights to Dispatch") must be coordinated with (1) the MOO (if any), (2) the continuing existence of Condition 1 and Condition 2 and (3) any related the market power mitigation. In particular, we continue to believe that RMR and RA are dissimilar products. To avoid price suppression, RMR Condition 2 units (particularly) should have no ubiquitous MOO and bids should be inserted and the unit should be dispatched only when reliability requirements demand its operation. As such, the "bid insufficiency test" may still be a necessary trigger for RMR dispatch.

NRG - The AS bid insufficiency test was included in the RMR contract to ensure that the ISO would use its markets, not the RMR contract, as the primary means to acquire AS. The ISO's proposal to require cost-based energy and AS offers from RMR units in all hours (presuming that the default RMR contract will be analogous to the current Condition 2 RMR contract) surfaces a version of the same concern – that the ISO will use the RMR contract to compel market participation at cost. Such compelled participation is not consistent with the current design of the RA MOO, which does not compel cost-based energy and AS offers. NRG does not oppose the elimination of the AS bid insufficiency test, but does oppose forcing cost-based energy and AS offers from RMR units in all hours, as NRG will discuss in item (h) below.

ii. Update Schedule M and Schedule C to include GHG compliance cost calculation, DAM and RTM gas price index, and updated SC charge calculation

Calpine supports changes to the RMR schedules that represent undeniable variable costs of operations such as those suggested above. As such, GHG costs must be included as well as any necessary modifications to represent current gas-price indices and GMC charges. In addition, we support the ISO developing a bid insertion tool, particularly for units under Condition 2. For these units, which recover their full costs of service, Calpine does not object to insertion of variable-cost-based bids when the unit is needed for a defined reliability event.

NRG strongly supports restructuring Schedule C to eliminate the archaic gas price mechanism. In so doing, the ISO must replace this mechanism with a mechanism that better reflects actual gas procurement costs. As the recent SoCal City Gate gas market dislocations (e.g., for July 23) painfully indicate, using gas costs that do not reflect actual market conditions not only leads to suppliers not recovering their costs, it also leads to running the ISO market on artificial gas prices, which will lead to inefficient and potentially problematic dispatch (e.g., if the ISO's market results call for burning more gas than can be reliably supplied). While fixing the impact on the ISO's markets from using an incorrect gas cost is outside the scope of this initiative, using the correct gas cost in Schedule C is required and clearly within the scope of this initiative.

iii. Update Schedule M to be consistent with bidding rules in ISO tariff and BPM

Calpine - See comment above.

NRG supports this.

iv. Seek input on defining a heat rate curve formula in Schedule C for multi-stage generator resources

Calpine supports, above all, consistency in the formulations of bid components between the contract and Masterfile. In particular, since the Masterfile contains the parameters used in market-clearing optimizations, Calpine supports the primacy of those Masterfile values. We are not convinced that Schedules A, C or M need to duplicate (as in schedule C1-7a, heat rates) any of the line items that are contained within the Masterfile. While the contract must contain sufficient data to calculate an RMR "rate", it seems more efficient that the Schedules merely refer to values embedded within the Masterfile.

NRG - Given that a MSG unit has different heat rates depending on configuration, NRG offers that where an MSG unit is designated as an RMR unit, then Schedule C will also need to be modified to allow for configuration-specific heat rates. Furthermore, some other schedule must be modified (Schedule D) or created (Schedule D-1) to account for MSG transition costs.

v. Other

Cogentrix proposes that the ISO evaluate incorporation of a retirement obligation into the RMR agreement. In order to maintain both system reliability and durable market signals, the ISO should ensure that any resource awarded an RMR agreement to prevent its retirement be prohibited from reverting back to a market based resource after the term of that agreement. Investors that remain captive to market revenues must be able to accurately predict market dynamics based upon the future supply, and relying on designated retirements is a fundamental part of that market analysis.

NRG - While NRG offers elsewhere in these comments that it may be easier to adopt a wholly new form of contract rather than trying to turn the RMR contract into an RA vehicle through piecemeal changes, should the ISO insist on modifying the RMR contract, it must also consider modifying other provisions of the RMR contract, including the ISO's authority to dispatch under Section 4.1, how contract service limits are determined and how service in excess of those contractual service limits is compensated.

PG&E - With regard to the *pro forma* RMR agreement included in the ISO Tariff, PG&E has consistently advocated for reforms to this agreement as soon as possible. The current *pro forma* agreement is out of date and needs to be revised before any additional RMR agreements are executed by the ISO. Revisions to the *pro forma* agreement should not be delayed while the ISO and stakeholders seek to work through other RMR and CPM issues. Instead, changes to the *pro forma* agreement should happen immediately.

g. Update allowed rate of return on capital for RMR compensation

Calpine does not believe a review of the pre-tax "allowed rate of return on capital" included in Schedule F of the pro-forma contract is necessary. Further review is unnecessary because (1) the current value yields and *after-tax* rate-of-return that is reasonable and (2) to Calpine's knowledge, every single RMR contract ever approved by the Commission has been the result of extensive negotiation which allows the parties to make adjustments to the revenue requirement they deem reasonable. However, if the ISO pursues that review, it must first recognize the significant differences between the Schedule F, pre-tax rate-of-return and referenced after-tax values. The rate-of-return identified in Section 5 of Schedule F is an estimate of the *pre-tax* weighted-average, rate-of-return, and includes an adjustment should interest rates exceed those established in the original settlement. The Straw Proposal conflates pre- and post-tax values when it references California IOU's *after-tax* return-on-equity, and *after-tax* cost-of-capital. These two definitional "rates-of-return" are very different, as highlighted by Mr. Murtaugh verbally in the stakeholder meeting and subsequently with the Market Surveillance Committee. One cannot directly compare a 12.25 total *pre-tax* rate-of-return and a 10.57 *after-tax* return on equity without also knowing the project specific leverage, cost of debt, deferred tax implications, and tax rates. In fact, assuming California and Federal tax rates of 11 and 21 percent, respectively, a 12.25 *pretax* rate-of-return would yield only an 8.33 *after-tax*, rate-of-return (12.25 * (1- (.11+.21)) or 8.33 percent) before any further adjustments. Even though Calpine believes the 12.25 percent pre-tax rate to by just and reasonable and needs no further consideration, Calpine cautions consideration of the refinement of a "proxy" after-tax, rate-of-return for RMR units. Doing so would require substantial changes to Schedule F, including the specific identification of tax rates and a revenue requirement "gross-up" representing the tax effects. Of the proposals offered, we specifically and vigorously object to any obligation to establish, from a blank slate, an after-tax rate-of-return for each RMR on a case-by-case basis. This proposal would significantly increase the burden on both the resource-owner prior to filing and on the ISO/PTO during RMR negotiations. In addition, it would require substantial modifications to the Schedule F.

NRG does not oppose re-examining the rate of return allowed in Schedule F. NRG agrees with Calpine that a new rate must account for the fact that this rate of return is specified to be a pre-tax rate of return. With regards to how this rate of return is set, NRG's strong preference is that the RMR owner be allowed to offer a proposed rate of return in its RMR rate schedules (ISO option 4).

PG&E supports revising the current fixed 12.25% after-tax rate of return specified in the RMR *pro forma*. There are several possibilities for revising the *pro forma* rate of return. One approach, in the appropriate circumstances, would be to have the rate of return set at the same rate as the PTO's return on equity. *See e.g. Bluegrass Generation Co.*, 118 FERC ¶ 61,214 at P. 86 ("The Commission has generally allowed merchant generators to use the interconnected utility's authorized rate of return as a proxy.") In any event, the current fixed 12.25% after-tax rate of return was determined at a time when the federal corporate tax rate was 35% and should be immediately reduced to reflect the lower federal tax rate of 21%. To properly reflect the tax law change, PG&E estimates that the current fixed rate of 12.25% would be reduced by 1.75%.

The Six Cities support the ISO's proposal to update the allowed return on capital in the RMR *pro forma* agreement (Straw Proposal at 18, 23); the Six Cities discuss below their recommendations regarding the appropriate mechanism for updating the allowed cost of capital under the RMR *pro forma* agreement. With respect to the methodology for updating the allowed cost of capital under the *pro forma* RMR agreement, the Six Cities support the ISO's proposal to update the allowed rate of return on capital for RMR compensation. As the ISO acknowledges, the current rate was established a number of years ago, and it has not been updated to reflect current capital market conditions. At this time, the Six Cities are not advocating for a specific methodology or approach to updating the rate of return on capital, but provide for consideration by the ISO and other stakeholders several general principles that should apply in the context of establishing a methodology to update the rate. First, FERC policy should apply to the derivation of the rate of return on capital. Based on current policy, the rate of return on capital should be determined based on application of the two-stage discounted cash flow ("DCF") methodology. For individual utilities of average risk, FERC has previously ruled that the median point estimate of the DCF range should establish the rate. If the same rate of return on capital will be applicable to multiple companies within the same RTO or ISO, FERC policy has been that the midpoint of the DCF range should set the ROE. DCF results vary depending on the risk profile of a particular utility and the time period being evaluated. Second, it is not appropriate to apply incentives, adders, or other approaches to increase the return on capital as suggested in the Straw Proposal (*see, e.g.*, Straw Proposal at 23, 24) to compensate resource owners for any special risks, such as status as an RMR resource. Such adders are unwarranted given that the RMR construct provides for full compensation to resource owners based on their costs, plus a reasonable return. No party has demonstrated that there are any special risks associated with RMR status for which an increase to the DCF-determined rate of return on capital is appropriate. Similarly, there is no basis for providing an increase in the rate of return on capital associated with an RMR resource's geographic location within the ISO Balancing Authority Area. The Six Cities also do not support application of an ISO/RTO membership adder to the rate of return on capital for RMR resources, nor do the Six Cities support increasing the rate of return based on claims of anomalous capital market conditions. Third, the ISO should recognize that, while FERC does have a methodology that has been historically used to establish rates of return on equity, and the Six Cities support primary reliance on that methodology to set the rate of return for RMR resources, the application of that methodology is not without controversy. Different parties interpret and apply the FERC DCF methodology in different ways. For this reason, FERC-authorized rates of return on equity for ISO Participating TOs are often determined through settlement agreements. For utilities that do not have formula rates, TRRs established through settlements often are expressed on a "black box" basis and do not specify an ROE component. For utilities that do have formula rates, the rate of return on equity is generally the product of settlement discussions and may reflect an increase or a decrease over the median or midpoint of DCF results, depending on various considerations during the settlement process. Thus, at least with respect to FERC-jurisdictional rates of return on equity, it is not accurate to state that "the investor owned utilities … have documented methodologies to complete such calculations." (*See* Straw Proposal at 23.) In the absence of stakeholder consensus around a particular methodology for updating the rate of return on capital, requiring RMR resource owners to propose, support, and submit their proposed rate of return on capital to FERC for approval would likely prove to be the most workable solution to this issue. However, the Six Cities are open to consideration of alternatives that would produce just and reasonable rates for RMR service, and look forward to continued discussions among stakeholders related to the relevant rate of return on capital. Regarding the process for completion of this stakeholder initiative, on which the ISO requests input at page 8 of the Straw Proposal, the Six Cities do not see a need at this time to deviate from the process followed generally in the ISO's stakeholder initiatives. It is not clear at this point whether the ISO's recommendations in the Straw Proposal will be unusually contentious or difficult to resolve through the customary stakeholder process, including with respect to the rate of return on capital. If comments submitted on the Straw Proposal reveal an unusually high level of controversy, it may be appropriate to consider whether some alternative process could be more efficient or constructive, but it seems premature to consider modifications to the generally applicable stakeholder process at this time.

h. Make RMR resources subject to a must offer obligation

Calpine - As we have indicated in several comments, Calpine believes that a MOO applied to Condition 1 (where the unit-owner is depending upon market revenues) is complementary to the inherent incentives and therefore not objectionable. We also agree that in the case of Condition 1, the bids submitted by the unit owner can be at any level, subject only to bid caps. However, we also believe that in the case of Condition 2 units, where a unit-owner is indifferent to market revenues because of the market revenue claw-backs, forcing the resource to bid at costs all hours would unduly suppress energy market prices. As such, we support bid insertion for Condition 2 units, but only when a reliability need is in evidence. FERC has found (in *Devon Power*) that use of RMRs, alone, has a deleterious effect on markets. A continuous MOO multiplies those effects, particularly when the unit is not needed by any reliability requirement: "[*E*]*xtensive use of RMR undermines effective market performance. In addition, suppressed market clearing prices further erode the ability of other generators to earn competitive revenues in the market and increase the likelihood that additional units will also require RMR agreements to remain profitable.*"

Cogentrix - Competitive and transparent pricing of RA is critical to the efficient entry and exit of resources. With respect to backstop procurement mechanisms, RMR in particular, Cogentrix believes that more detailed studies should be completed prior to implementing a MOO for resources with RMR contracts to determine the extent of the market distortions caused by the subsidized supply. In creating a MOO requirement for RMR resources, Cogentrix sees possibility of RA price suppression by resources that are already receiving cost-of-service revenue and, therefore, have no incentive to bid prices that accurately reflect their cost and profit requirements. Over the medium to long term, the ISO should expect that imposing a MOO requirement for RMR resources will continue to distort price signals, suppress RA prices and increase retirement requests and backstop procurement as a result.

CPUC - Staff supports the ISO proposal to add a MOO to RMR resources in addition to subjecting the resources to RAAIM. Applying the same MOO and RAAIM to RMR resources that is applied to RA resources will eliminate the possibility of providing an incentive for generators to use the RMR process over the bilateral procurement process. Staff also supports the RMR pro forma performance penalty provisions in addition to RAAIM. Having both will discourage generators from using the RMR mechanism over the bilateral process, which is one of the key goals.

NRG - The ISO is proposing to use the RMR contract both to (1) take RA-equivalent service from units that would otherwise retire but are required to remain in operation and (2) to subject such RMR units to a 24 x 7 cost-based MOO. NRG does not support the ISO's proposal for subjecting RMR units to a MOO for several reasons. *First,* nothing in the current RA program design compels RA units to submit *cost-based* offers for energy and AS; while RA units are required to submit energy and AS offers, RA units may submit *market-based* offers. *Second,* this proposal represents a significant departure from the current requirements of Condition 2 of the RMR contract, which require cost-based offers *only* when the RMR unit is required to operate to maintain local reliability or mitigate non-competitive congestion. *Third,* forcing full-time cost-based offers from a unit that would have otherwise retired but cannot because it is required to operate under some conditions to maintain *local* reliability has the potential to unduly impact energy and AS market prices at times when the unit otherwise would not be running. Units that the ISO forces into continued operation for local reliability should be operated only when they are required to operate to maintain local reliability. The ISO is essentially looking to turn the RMR contract, which was originally intended to allow the ISO only to access cost-based energy under limited conditions and not to compel market participation under all conditions, into a vehicle under which to take generic RA service. NRG holds that the ISO would be better off to scrap the RMR contract altogether and create a wholly new contract for this purpose than to try to re-form the RMR contract into a purpose for which it was never intended. Schedule F should remain the pricing core of this new contract, which also should, consistent with the existing RMR contract, contain provisions to compel cost-based offers and credit back net market revenues when the unit is required to operate for local reliability. Given that under the ISO's new proposed structure, a unit would not be designated as RMR unless it was required to operate beyond the time at which it wanted to retire, the ISO should not do further damage to energy and AS markets already compromised by the number of resources who do not depend at all on the ISO's markets to recover any of their costs by forcing cost-based offers from units that should be retired but must remain in operation for specific, limited reliability reasons.

PG&E supports the extension of the full RA MOO to both RMR Condition 1 and Condition 2. Under the RMR Condition 2 structure, where customers pay for the full use of the RMR generator under cost-of-service ratemaking, they should obtain in return the full benefit of any capabilities of the unit that can be economically delivered through market participation without impairing the reliability function which prompted the RMR designation in the first place. Similarly, RMR owners electing Condition 1 should be under a MOO, as well, so that customers receive the full value of the RMR agreement.

SCE - As stated in other parts of these comments, the MOO should be consistent between RMR and CPM resources with consistent non-performance measurement (based on availability) and penalties (based upon compensation).

The Six Cities support the ISO's proposal to apply a MOO to all CPM and RMR resources (Straw Proposal at 17 – 18, 25 – 26); the MOO should apply to any and all products that CPM and RMR resources are capable of supplying.

WPTF does not oppose a MOO on Condition 1 RMR resources but notes that a MOO on Condition 2 RMR resources would adversely impact market prices. Applying a MOO on Condition 1 RMR resources aligns with the incentives of Condition 1 in that the resource owner is relying on market revenues. This is not the case for Condition 2 resources. Forcing Condition 2 resources that are indifferent to market revenues to bid in at cost during all hours will suppress market revenues. Alternatively, the ISO could explore other modifications that would allow for better MOO and RAAIM rules, such as those outlined below. WPTF believes that the ISO should clearly differentiate between resources that want to retire because they are old or soon to be replaced and resources that simply are uneconomic due to RA market issues but needed for grid reliability. The following, illustrative alternative, better aligns the MOO and RAAIM rules and addresses the CPUC's issue of cherry-picking brought up at the August 5 Market Surveillance Committee meeting. Below we provide an illustrative example of three different general backstops that could be used to differentiate between resource types. WPTF is not tied to this proposal, but simply notes that an additional mandatory CPM category could allow design changes to the RMR product, and payment changes to resources that submit their retirement, and these changes may be more acceptable to a range of stakeholders. This could also be done by further modifying the ISO's existing proposal and creating two more distinct RMR types. Illustrative Backstops: <u>RMR: *Mandatory, retirement required*</u>***.*** Used as a true runway for resources that are exiting the market due to their age and condition but are needed until alternatives can be put in place. If a resource gets an RMR contract, then (1) the ISO Transmission Planning process must evaluate generation and transmission alternatives during the next available opportunity and (2) the owner must retire the resource once the alternatives are in place. These resources would get current full cost of service payments, not have a MOO, and have availability rules similar to today. Mandatory CPM: *Mandatory, no-retirement required.* This would be used for resources that want to exit the market for economic (or other) reasons and so have sent in their retirement notice, but are needed for local or other reliability issues. The difference between this and the RMR is that these resources expect to reenter the market or want to retain that option. These resources would be paid their GFFCs and be under a time-limit to reenter the market. They would have a MOO and be exposed to RAAIM similar to other CPM resources if needed for capacity. The timing could coordinate with the annual RA process, which would allow the mandatory CPM to have differing lengths. Voluntary CPM: *Voluntary to offer into CSP process, mandatory acceptance after that.* This would be used as a backstop for RA just like the current proposal, and the tariff would be updated for any needed changes. For example, bidding changes in the annual CPM process requested by generators such as an annual guarantee instead of monthly (or annual price and individual monthly prices), and a tariff review to ensure the all offers into the CSP are mandatory if accepted. These resources would be paid their offer price or up the current ISO cap calculated as GFFCs.

i. Make RMR resources subject to the Resource Adequacy Availability Incentive Mechanism

Calpine agrees that RMR resources should have availability incentives. RAAIM is an example of an incentive which creates both rewards for and penalties associated with the economic bidding process. It only indirectly encourages physical availability (that is, if a unit is forced out, it cannot bid.) Tailoring this mechanism to an RMR is incongruous and would require changes to the long-delayed and technically detailed RAAIM process. First, an RMR *must* self-schedule when the market does not support operation, but the unit is required for reliability. Because it is not considered an economic bid, a self-schedule would unjustly expose the resource-owner to penalties when complying with an ISO Dispatch Order. Second, to the extent that bid-insertion is in place during hours of need, a resource-owner could receive RAAIM incentive payments (for high availability) in addition to other fixed cost recovery. Moreover, unlike an RA unit, an RMR unit has no ability to substitute in order to manage or avoid RAAIM. Calpine believes that the incentives in the current RMR pro-forma are better tailored to RMR units. In fact, the current Section 8.5 (Schedule B) Availability Charges have a direct and immediate effect on capacity payments if a unit experiences outages beyond those considered and negotiated as part of the agreement. Under no circumstance would Calpine support exposure to both RAAIM and the pro-forma's Availability Charges.

CPUC - Staff supports the ISO proposal to add a MOO to RMR resources in addition to subjecting the resources to RAAIM. Applying the same MOO and RAAIM to RMR resources that is applied to RA resources will eliminate the possibility of providing an incentive for generators to use the RMR process over the bilateral procurement process. Staff also supports the RMR pro forma performance penalty provisions in addition to RAAIM. Having both will discourage generators from using the RMR mechanism over the bilateral process, which is one of the key goals.

NRG strongly agrees with the premise that RMR units should be subject to either the availability incentive mechanism present in the RMR contract **or** RAAIM but not both. NRG cannot now say that it supports subjecting RMR units to RAAIM instead of the RMR availability incentive mechanism for several reasons. *First,* NRG's understanding is that RAAIM is almost certainly going to undergo significant modification soon, and the next form of RAAIM is not known. *Second,* the RAAIM penalty price may be misaligned with the imputed capacity price paid under the RMR contract. This misalignment may create undue risk for the RMR unit owner if the RAAIM price is higher than the imputed RMR price. Finally, RAAIM is currently intended to create an incentive for a resource to offer in all hours, something that NRG opposes being applied to the RMR contract, as noted above.

PG&E - The ISO's proposal should continue to use the non-performance penalties to incent performance for both the RMR Dispatches and Market Transactions for all RMR resources. The current RMR penalties in the RMR agreement should be used to incent performance. The RMR unit should remain exempt from RAAIM performance penalties and be subject to Non-Performance penalties pursuant to the current tariff. RAAIM penalties are lower than the Non-Performance penalties and could incent generators to operate in a manner that precludes them from providing the services when needed the most. The objective of RAAIM was to create an incentive for resources to meet the MOO by providing replacement capacity when resources go on outage in a given availability assessment hour. RMR resources do not have the ability to provide replacement since they are the only resource that can provide the reliability service, and the reliability need that the resource is providing may not coincide with the assessment hours (e.g., voltage support is needed for hours outside peak-demand hours). 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.

SCE - There should be consistent non-performance measurement (based on availability) and penalties (based upon compensation). SCE supports RAAIM-like performance incentives, as stated in other parts of these comments. The penalty mechanism should not be a fixed price but rather a claw-back of the contract payments commensurate with the period of unavailability. The ISO should develop a standard for maintenance outages that if the outage request is approved by the ISO, would not result in a contract revenue claw-back.

The Six Cities support the ISO's proposal to apply the RAAIM to all CPM and RMR resources (Straw Proposal at 17 – 18, 26 – 27); the RAAIM provisions should apply to any and all products that CPM and RMR resources are capable of supplying;

WPTF - While WPTF supports having availability incentives in place for RMR resources, RAAIM is not the best way to provide such incentives. For example, the current pro-forma agreement availability charges may be more appropriate than exposing RMR resources to RAAIM.

j. Consider whether Condition 1 and 2 options are needed for RMR

Calpine sees no reason to eliminate Condition 1, especially given that the ISO proposes the discretionary right to allow Condition 1. We also support the continued availability of Condition 2 and the unit-owner's discretion to choose between the two options.

NRG does not oppose the ISO's position to keep both options but use Condition 2 as the default.

The Six Cities support the ISO's proposal to provide in the RMR *pro forma* agreement a default compensation mechanism under which RMR resources will be paid for their costs of service (including an allowed rate of return on capital based on net plant and potentially including major maintenance expenses), with any market revenues earned above the cost of service credited against monthly fixed costs, but with discretion for the ISO to negotiate in appropriate circumstances a compensation arrangement under which an RMR owner would be paid less than its full cost of service and be permitted to retain market revenues earned above its cost of service (Straw Proposal at 17 – 18).

k. Ensure RMR designation authority includes system and flexible needs

Calpine supports the ISO's proposal to use RMR to designate any resource at any time. As the fleet of gas-fired resources is systemically culled, virtually all remaining resources will be needed to meet some reliability requirement. Calpine supports the proactive expansion of the ISO's designation authority to include both System and Flexibility needs. This expansion of authority, while important, would be exercised highly infrequently if Calpine's holistic reforms are implemented and RMR becomes the "last gasp" alternative.

CPUC - Staff does not support the ISO expanding its RMR tariff authority to flexible and system capacity. Expanding the RMR tariff authority will again provide generators with the opportunity to utilize the RMR process rather than the bilateral process (and the CPM process) to secure revenues. This is because resources seeking to retirement could potentially be paid higher revenues through an RMR contract then they could through a bilateral contract. Expanding RMR will lead to further front running of the competitive bilateral process.

NRG does not oppose designating units that would otherwise be retired as RMR to meet system and flexible capacity needs. Consistent with NRG's response above, such units should be required to submit cost-based offers *only* when they are required to operate to cure the deficiency for which they were designated RMR – e.g., when there are operational system capacity or flexible capacity deficiencies that cannot be cured through RA units.

ORA - At the July 11 stakeholder meeting, the ISO clarified that it would only designate units as RMR for system or flexible needs if the resource owner provides a letter stating its intent to retire a resource and the ISO determines a need for the resource. If the ISO moves forward with this aspect of the proposal, the ISO should clarify this intent in its proposal, because there was confusion that the ISO might designate units as RMR simply because the resource owner rejects a CPM designation. However, it is not clear that the ISO's proposal to extend its RMR designation authority to system and flexible needs is necessary or beneficial. LSEs have exceeded their system and flexible RA requirements in 2017 and can own additional capacity that they do not show for RA purposes. The CPUC Integrated Resource Planning (IRP) process will ensure the procurement of new resources to meet capacity needs over the longer term planning horizon; the current IRP cycle plans out to 2030. It seems very unlikely that the ISO would ever reach a point where it would need to RMR a unit for system or flexibility reasons. LSEs are required to show procurement of 90% their system RA obligation for the five summer months and 90% of their flexible RA obligation for all twelve months. They are also required to show 100% of their monthly system and flexible RA on a month-ahead basis. LSEs do not need to procure system or flexible RA resources in specific local areas so there is a larger pool of resources to procure to meet RA requirements. If RA showings fall short of system or flexible capacity requirements, the ISO has the ability to designate resources to provide capacity through CPM. If a resource rejects an initial CPM designation, the ISO can require resources to respond to Exceptional Dispatch CPM which is mandatory. The ISO has not addressed whether it would seek an annual RMR contract for system or flexible needs depending on the duration of any actual need. For example, if a resource would only be needed for one month of the year for system or flexible capacity, would the ISO seek a one-year contract for the resource or would it consider CPM Exceptional Dispatches instead? ORA is also concerned with the interaction between the proposal to apply RMR to system and flexible capacity and the proposal to designate a resource as RMR that is needed for years two or three. These proposals could potentially lock-in resources to RMR agreements if the ISO sees a need in years two or three, even though load forecasts can change and new solutions can come online in a short period of time to obviate the need. Additionally, the ISO has reported a delay in its Flexible Resource Adequacy Criteria and Must Offer Obligations Phase 2 (FRACMOO2) stakeholder initiative, which would lead to changes in flexible RA requirements. Therefore, the ISO's proposal could lock-in resources to RMR agreements that may not actually meet flexible capacity needs in the future. The ISO should address these concerns before moving forward with this proposal.

PG&E does not support expanding the ISO's authority under the tariff to issue RMR designations for system or flexible needs. The current excess in system capacity precludes the possibility of an RMR designation being needed to preserve system reliability. Over the forward planning horizon, the RA requirements (including planning reserve margins) should be sufficient to guarantee that system resource needs are met. Moreover, even if enough capacity not picked up for RA were simultaneously to seek retirement, RMR designations would be triggered for many of these units to meet local needs before any possible system deficiency could occur. Flexibility is not a transmission reliability attribute for which an RMR would be an appropriate remedy. Costs for flexible needs should not be allocated to customers as a transmission charge but rather as a procurement cost. Flexibility is a characteristic of the mix of generation resources and the need to procure sufficient flexible reserves to manage uncertainty in the forecasting of both load and resource behavior at different forward time intervals. Given the availability of energy, ancillary service, and capacity market instruments to procure flexibility, it is unclear what additional flexible system characteristics might warrant the designation of an RMR for a particular unit at risk of retirement. Creating a new RMR for flexibility will only serve to grant a guarantee of cost-of-service regulated transmission rate recovery to those flexible units that threaten to retire early, incenting further gaming of the retirement process.

SCE - All attributes of a resource should be considered procured, even if the procurement decision is for only a specific attribute. Thus, if a flex resource is procured for a non-flex reason, the flex attribute is still procured by the ISO and should be allocated. In addition, the MOO should be for the resource to bid economically for all resources to ensure appropriate market outcomes. The bid should be set at the default energy bid for the resource to appropriately reflect its marginal cost in the optimization of the market. SCE notes that there will be certain periods that the default energy bid may not be appropriate such as during the late night/early morning hours to avoid the optimization cycling a resource unnecessarily.

The Six Cities support the ISO's proposal to provide authority for the ISO to make RMR designations and to dispatch RMR resources for system and flexible needs as well as for local needs (Straw Proposal at 18).

l. Allocate flexible RA credits from RMR designations

Calpine supports an allocation of all attributes (flex, local or system) of backstop contracts to loads, based, in the first instance, on unmet requirements or purposeful short-positions and second, on actual load ratio shares.

CPUC - Staff supports the CAISO's proposal to allocate flexible benefits of RMR designations to LSEs. In addition, Staff request that the ISO clarify that the system benefits will also be allocated.

NRG does not oppose allocating flexible RA credits arising from RMR designations. Again, NRG would oppose imposing a cost-based obligation to offer in all hours on RMR units.

ORA supports allocation of flexible RA value for RMR resources, because it would ensure that ratepayers get the full value of the cost for RMR resources. Counting the flexible RA value of RMR resources also decreases the risk that ratepayers will pay for additional unneeded flexible capacity.

SCE - All attributes of a procured resource should be allocated, regardless of the reason for procurement.

The Six Cities support the ISO's proposal to allocate Flexible RA credits from RMR designations (Straw Proposal at 27 – 28).

m. Streamline and automate RMR settlement process

Calpine - Yes. Please.

NRG does not object to using existing CAISO market settlement systems to streamline and automate RMR settlements if RMR units would be walled off from any exposure to CAISO market defaults or to other CAISO charges that are based on market participation. It is NRG's understanding from the July 11 meeting that the ISO is proposing to insulate RMR owners from any allocation of a market default.

n. Lower banking costs associated with RMR invoicing

Calpine - Yes. Please.

NRG supports this aspect of the CAISO's proposal.

CPM

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

Calpine - See above. Allocations should be based on deficiency, first, then based on actual load ratio shares.

CalCCA - The ISO was asked about the billing calculation for collective CPM under the ISO CPM Tariff, 43A.2.2.1. The tariff does not allow for an individual LSE to be credited the CPM cost for their share of a collective deficiency should they have purchased MWs from the unit that is being CPM'd. Instead the "collective deficiency" is credited, leaving still a large cost obligation to the individual LSE. We ask to have a new initiative added to the stakeholder catalog to discuss further and recommend changing the tariff. CalCCA will be starting that formal process.

NRG - The issue of how to address load migration is complex and difficult. To the extent that some procurement obligations are assigned based on forecast and trued up later based on actual load, CPM costs should be treated similarly. To the extent that cost allocations are based on forecasts and not trued up later, then CPM costs should be treated similarly. For example, CPUC Decision D.18-06-030 now requires CCAs to participate in the year-ahead forecasting process. This means that there should be a year-ahead load forecast for CCAs just like there is for IOUs. Allocating CPM costs based on similar load forecasts will be equitable if the forecasts are reasonably accurate. To the extent the forecasts are not accurate – that is a problem outside of the allocation of CPM costs.

ORA supports further investigation and discussion of year-ahead CPM cost allocation. The costs of the Encina and Moss Landing CPM designations for 2018 were charged to LSEs based on prior-year load forecasts rather than actual loads, as the Straw Proposal describes. This is a significant problem due to load migration observed for 2018 and expected in near future years. The ISO claims that the CPUC's Decision (D.) 18-06-030 mitigates much of this concern, since it requires CCAs to participate in the year-ahead forecasting process, which will provide more predictable patterns of load migration. That Decision, however, cannot account for unpredictable changes to load migration throughout the year, such as a delay in a CCA's start date. The ISO's effort to create a holistic approach to altering the CPM and RMR tariffs should include new provisions to true up cost and credit allocations.

SCE - The ISO cited the June 2018 CPUC decision requiring all LSEs to participate in the year-ahead RA process, as largely addressing this issue. SCE agrees, but cautions that should there be any changes pertinent to all LSE participation in RA, the CAISO should revisit this topic.

2. Evaluate if load serving entities are using CPM for their primary capacity procurement

Calpine understands that several LSEs in the San Diego load pocket sought waivers of the local requirements, and that ultimately CPM was used to acquire capacity. We agree with the ISO that these events do not constitute a cause for opening the CPM settlement or pricing conditions.

NRG agrees with the ISO's assertions that (1) trigger 2 set forth in the May 2015 Offer of Settlement was met (some LSEs relied on CPM for more than 50% of their RA obligations) and (2) that the CPM design was not responsible for this outcome. In other words, LSEs' reliance on CPM at the end of 2017 was the result of two things: (1) provisions of D.12-04-046 that prevented SDG&E from contracting with Encina in the year after its original OTC compliance deadline, and (2) the mismatch between unit size and the small RA quantities being sought by small buyers and NRG's reasonable position that it required a critical mass of commitments above these small amounts to keep the plant in continued operation. The ISO's notification to CPM Encina was not issued until December 22, 2017, well after the deadline for annual RA showings. Thus it appears that while the letter of the second trigger was met, it was more the timing of the designation and the misalignment between unit size and LSE requirements than the fundamental CPM design that encouraged LSEs to rely on CPM than led to this outcome. In any case, the ISO has decided to re-examine various aspects of CPM as part of this stakeholder process.

Other Comments

Calpine continues to believe that capacity compensation and the ISO's use of backstop must be viewed holistically, and that the ISO has the necessary and independent authority within the four corners of its tariff to make substantive and beneficial changes to efficiency and effectiveness of overall capacity commitment and compensation. In this regard, we refer to Calpine's presentation of May 30th (see at http://www.caiso.com/Documents/CalpineSupplemental-ReviewofReliabilityMust-RunandCapacityProcurementMechanism-StrawProposal.pdf), which recommends comprehensive changes to the RA timeline and the ISO's backstop auction. These proposals facilitate a multi-year forward RA requirement, enforcement of local sub-areas, create a reasonable runway for generation-owner retirement/operating decisions and affirmatively places the ISO in the position of a central buyer for unmet reliability needs. While Calpine is concerned that the ISO has deferred decision-making on these matters to the CPUC, Calpine appreciates that the ISO has reflected many of these positions in its comments in the CPUC RA dockets. With that, we offer the comments above on the ISO's more-narrow proposals to reform RMR and CPM.

Cogentrix recognizes the importance of grid reliability and the fundamental logic of the ISO having the ability to "secure essential services from resources to reliably operate the grid" in the absence of those resources availability in the market. However, Cogentrix notes with concern the increased use of backstop procurement, RMR agreements in particular, by the ISO over the past two years. By their very nature, backstop procurements by the ISO distort markets and are economically inefficient, driving out legitimate competitors and leading to higher prices for rate payers. They reduce the economic incentives for investors to innovate and improve the operating efficiency of resources that have been denied the benefit of out-of-market revenues. Ultimately, inefficient markets fail, stranding investments and causing physical interruptions of supply. Consistent with comments in related stakeholder processes, Cogentrix opines that the increase in backstop procurement by the ISO is symptomatic of a dysfunctional RA framework that does not provide essential reliability resources with sufficient market revenue to support continued investment in maintenance required to operate. Cogentrix strongly encourages the ISO to explore and prioritize wholesale reform to the RA framework.

NRG - At the July 26 Board meeting, a PG&E representative offered that reforms to the RMR contract were urgently needed – a sentiment shared by a member of the ISO Board. NRG strongly disagrees. Given that the fundamental design of the RA program is under investigation in Track 2 of the CPUC's RA program, NRG opposes pressing forward with "urgent" changes to the ISO's RA backstop mechanisms until the new design of the RA program has been determined and implemented. There is an undeniable interplay between the RA program and the ISO's RA backstop mechanisms (which the ISO now proposes to expand to include RMR). Making fundamental changes to the ISO's backstop mechanisms before the final design of the RA program has been committed has the potential to create a substantive misalignment between the two programs, to the potential detriment of both. If Track 2 remains on its current schedule, with a proposed decision by the end of 2018, then the ISO's proposed timing of this stakeholder initiative, which would result in presentation to the Board in March 2019, may align very well with the Track 2 schedule. Should the Track 2 schedule slip, NRG would strongly oppose moving forward with making a recommendation to the Board on modifying the ISO backstop mechanisms prior to the CPUC committing to fundamental RA program redesign.

PG&E - Overall, PG&E supports the direction the initiative appears to be headed in, holistically reconsidering significant features of the RMR and CPM in order to better align incentives in light of current market realities for gas-fired generators at risk of retirement. While PG&E has expressed concern regarding the slow pace of reform, and continues to be concerned by the possibility of additional, expensive backstop procurement, we believe the general direction of these reforms is correct and will result in improvements in cost-effectiveness in the longer run, especially in combination with the scope of changes being contemplated in the CPUC's RA Track 2 proceeding.

Powerex agrees that a holistic examination of the existing CPM and RMR frameworks is warranted and that additional efforts are needed to strike an appropriate balance between ensuring that the ISO has appropriate backstop procurement authority to maintain reliability while continuing to promote the primary procurement of capacity by LSEs through the RA program. Powerex believes, however, that additional efforts are necessary to ensure that the ISO's backstop procurement needs can be met using the most efficient and cost-effective set of resources available. In particular, Powerex believes that there are elements of the existing CPM framework that act as barriers to external resources competing to obtain a CPM designation. Among other things, at an August 2, 2018 web conference concerning the ISO's upcoming intra-month CSP for September 2018, the ISO stated that it believes that external resources are ineligible to offer to supply capacity in the intra-month CSP. In addition, under the ISO Tariff, a resource located outside of the ISO balancing authority area may not offer to supply capacity in the annual and monthly CSPs unless the resource obtains an allocation of maximum import capability ("MIC") in accordance with Section 40.4.6.2.1 of the ISO Tariff. Powerex believes that limiting the ability of external resources to participate in the CPM process is highly inefficient, as well as inappropriate. As a practical matter, the effect of the limitations set out above is to prevent external resources from competing to meet ISO's backstop procurement needs, even when they are fully capable of providing the services being procured, and are able to do so efficiently and cost-effectively. Powerex believes that it is counterproductive to artificially limit the pool of resources that are eligible to meet the ISO's backstop procurement needs and that there is no technical justification for categorically excluding external resources from participating in CPM CSPs. Powerex urges CAISO to take steps to facilitate the participation of external resources in CPM CSPs. As a first step, the ISO should immediately clarify that external resources are eligible to participate in the intra-month CSP. Notwithstanding the ISO's statement at the August 2 web conference, there does not appear to be any basis in the ISO Tariff for prohibiting external resources from participating in the intra-month CSP. Moreover, while the ISO cited Section 5.3.3(6) of the BPM for Reliability Requirements in support of excluding external resources from the intra-month CSP, that section does not prohibit external resources from participating in the intra-month CSP process. Instead, that section merely states that external resource offers into the annual and monthly CSPs must be less than or equal to the "available (net) import capability on the branch group to which the resource is associated." Thus, there is no apparent legal or technical basis for excluding external resources from the intra-month CSP. Accordingly, Powerex requests that the ISO clarify that external resources may participate in the intra-month CSP, subject to meeting the eligibility requirements set out in the ISO Tariff (*e.g.*, the requirement to obtain MIC). If CAISO cannot provide such clarification, Powerex would appreciate the ISO further identifying which tariff provisions or business practices prevent the participation of external resources. Powerex also believes that the ISO should take steps to ensure that the existing MIC allocation framework does not stand in the way of ensuring that the ISO is able to meet its backstop procurement needs using the most efficient and cost-effective resources possible. As Powerex has explained at length in comments filed in numerous ISO stakeholder proceedings, Powerex believes that the existing MIC allocation framework represents a substantial barrier to the competitive and efficient procurement of RA capacity, and that the ISO should convene a stakeholder process focused on revising the MIC allocation framework. At a minimum, however, the ISO should modify the CPM framework to ensure that the MIC allocation framework – and the inefficient stranding of capacity associated with that framework – does not stand in the way of the ISO efficiently procuring backstop capacity. In the event that CAISO believes that any procurement of backstop capacity from external resources needs to be supported by a MIC allocation, then the ISO should broaden the scope of this proceeding to consider how the ISO Tariff can be modified to prevent the stranding of intertie capability from impairing the ISO's procurement of backstop capacity. Among other things, Powerex believes that it would be appropriate for the ISO to evaluate the quantity of unused intertie capability that is available at the time that it conducts the CPM CSP and "claw back" unused MIC allocations as necessary to support its backstop procurement. It is important to recognize that, at the time that the ISO conducts its monthly and intra-monthly CSPs, the deadline for the submission of annual and monthly RA plans will have closed. As a practical matter, any LSEs holding unused intertie capability at that time are either stranding the capacity or treating it as a “costless” option that they can use to support resource substitution in the event that a resource that they are using to meet RA requirements is unavailable due to a forced or planned outage. Powerex believes that there is no justification for allowing certain LSEs to strand intertie capability to the detriment of the efficiency of the CPM framework.

WPTF supports the ISO’s direction to better differentiate between the CPM and RMR designations. It makes sense to postpone any larger overhaul for after the CPUC has concluded Track 2 and potentially Track 3 of the current RA Proceeding. This RA Proceeding is likely to address significant issues such as RA timelines, multiyear RA requirements, and central buyer paradigms. Therefore, WPTF supports the ISO’s current Straw Proposal scope but encourages the ISO to take this opportunity to consider changes to other aspects of capacity procurement outside of the backstops, such as the RA timeline.