Opinion on Reliability Must Run and Capacity Procurement Mechanism Enhancements

by

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I. Introduction and Summary of Recommendations

I.A. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator (CAISO) has been asked to comment on the ISO's proposed Reliability Must Run and Capacity Procurement Enhancements (RMR/CPM).[1] The initiative leading to this proposal has been addressed during MSC meetings on Aug. 3, 2018, Sept. 28, 2018, and Jan. 25, 2019.

Both RMR and CPM are forms of backstop procurement of resource adequacy (RA). When the CAISO determines that the bilateral RA market in California has not (or will not) result in sufficient resources to meet anticipated reliability standards, it has the authority to directly contract with resources to provide RA and other reliability services. The timing and a pricing of backstop contracts have long been contentious features, in part because the terms of backstop contracts can influence the strategies of buyers and sellers in the bilateral RA market.

The MSC has commented on various aspects of backstop procurement several times. The most directly relevant previous opinions made the following points.

- In 2007 the CAISO implemented an Interim Capacity Procurement Mechanism (ICPM). The MSC argued that the CAISO should have authority to obtain RA through backstop procurement, particularly in the instance of a "significant event" that alters the reliability situation in the CAISO.[2] This authority subsequently evolved into the CPM as it is applied to short-term (monthly) procurement. We also expressed concern over the central

[1] Reliability Must Run and Capacity Procurement Mechanism Enhancements, Draft Final Proposal, Jan. 23, 2019, http://www.caiso.com/Documents/DraftFinalProposal-ReliabilityMust-RunandCapacityProcurementMechanismEnhancements.pdf

[2] F. Wolak, J. Bushnell, and B. Hobbs. *Opinion on "Interim Capacity Payment Mechanism under MRTU."* November 2007.

role the must-offer obligation (MOO, as then constituted) was playing in RA policy. Given the rising share of imported, energy limited, and variable energy resources, the CAISO would have to explore options beyond the MOO as it was designed at that time.

- In 2010, the CAISO implement the CPM. The MSC reaffirmed its support for the CAISO's backstop authority, but also commented that CPM payments would ideally differentiate between areas with local resource scarcity and those with sufficient capacity that was not contracted for in the bilateral market.[3]
- A 2012 CAISO proposal addressed the risk of retirement of necessary resources – in that case, flexible resources. The MSC recognized that the CAISO has to be ready to intervene if a retirement of a critical resource appears imminent. However, we also expressed concern about the interaction between a pro-active backstop process and the annual bilateral RA process as it existed at that time.[4]
- In both 2010 and 2012, we observed that the need for CAISO backstop intervention could result from several factors, including either buyer- or seller-side market power. While we were not in a position to determine the extent to which either form of market power was influencing market outcomes, the potential for either price-discrimination on the part of buyers, or local market power on the part of resources has been a frequently raised issue by market participants and the CAISO itself. We noted that price discrimination on the part of RA buyers could result in long-run inefficiencies if it resulted in the addition of newer more expensive facilities and the retirement of lower-cost incumbent resources.
- We also in 2012 noted that, "as a general principle it is preferable to award flexible resources through short-run energy and ancillary services markets rather than through differentiated payments in long-run capacity markets" such as a forward RA market and its backstops.[5]

Several consistent issues have been maintained through each of these previous initiatives into the current one. These include questions about the appropriate level of compensation for backstop resources, as well as the interplay between these compensation levels and the potential for market power on the part of either local RA sellers or buyers. Another theme in the 2012 risk-of-retirement initiative was the interplay between bilateral RA procurement, market pricing, and the decision or need for a plant to seek permission to retire. These issues remain in the forefront in the present initiative.

This Opinion is structured as follows. A summary of our recommendations (Section I.B) are provided in this introduction. Section II discusses the current initiative in the context of California's resource adequacy policy. Section III outlines some key elements of the CAISO proposal. In section IV we comment on the CAISO draft final proposal and offer suggestions for possible changes.

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[3] Wolak, F., Bushnell, J. and B. Hobbs. *Opinion on the Capacity Procurement Mechanism and Compensation and Bid Mitigation for Exceptional Dispatch*, October, 2010.

[4] Bushnell, J., Harvey, S., Hobbs, B. and S. Oren, *Opinion on Flexible Capacity Procurement: Risk of Retirement.* September, 2012.

[5] Ibid., p. 4.

I.B. Summary of Recommendations

The MSC supports the general framework that is proposed for CPM. However, the MSC also recognizes that that actions by the CPUC and perhaps the California state legislature, as well as future ISO initiatives, may result in significant changes in RA policy. If such changes occur, elements of the CPM framework will need to be revisited. We also note that the current level of the CPM soft offer-cap needs to be re-evaluated. We understand that this cap is scheduled to be the subject of an ISO stakeholder process in the near future. The level of the cap will affect the relative attractiveness of seeking or accepting a CPM designation versus announcing an intent to mothball or retirement, with the possibility of receiving an RMR designation. As another example, the soft-offer cap initiative and other future processes might explore more comprehensive approaches to local market power mitigation in RA procurement.

The MSC also agrees with the general framework for RMR as targeting risk-of-retirement by resources needed to provide essential reliability services that are not sufficiently compensated for in ISO markets to be accompanied by cost-of-service payments for those units. We would support a regulatory approach that does not pro-forma link these cost-of-service payments to a depreciation schedule chosen previously by the unit owner, but instead determines an appropriate depreciation schedule on its regulatory merits.

We acknowledge concerns about resources with local market power potentially having an incentive to strategically claim an intent to retire. We note, however, that RMR generating units are not free to return to market unless their must-run status is removed through a transmission upgrade or other changes in market conditions. The RMR contract provides the CAISO with an option to renew under cost-based terms as long as the reliability need, and therefore the unit's local market power, remains. Therefore, a unit that chooses to enter into an RMR contract will not possess the same degree of market power upon returning to the market, if it chose to do so.

If toggling back and forth between market-based operations and RMR remains a significant concern, the option framework could be extended to give the ISO or some other party an option to renew the generator's RMR contract, even after the reliability need is resolved. However, we foresee difficulties with giving the ISO discretion over exercise of this option, so this would be a significant alteration to the RMR process.

The MSC agrees that performance requirements for RMR and CPM designated capacity are highly desirable, especially for RMR where there is no other economic incentive to be efficient and available when needed. Our understanding is that the RA Availability Incentive Mechanism (RAAIM) would be applicable for 17 hours per day, 7 days per week, so generators that comply with that requirement are very likely providing the reliability services that are needed under almost all foreseeable scenarios. For extremely idiosyncratic scenarios in which a unit is needed at other times, the ISO could maintain the ability to negotiate targeted performance metrics for units that are meeting niche reliability needs.

The MSC agrees with the proposal to apply a must-offer obligation on RMR and CPM plants. However, it is crucial to ensure that default energy bids (DEBs) reflect all critical costs. A particular issue is increased maintenance costs that might be necessary if an older, less reliable unit is dispatched or made available for a large number of hours.

Another concern with applying the RAAIM mechanism is that CPM or RMR status might be granted to generators with high outage rates near the end of their useful life. It might be uneconomic to make investments to reduce these outage rates to levels that would avoid RAAIM penalties because of the unit's short remaining life or other for reasons. As a result, a RMR unit that is near the end of its useful life and experiencing or expecting high outage rates might reasonably expect to incur RAAIM penalties that would be unrecoverable under present RMR rules.

The CAISO proposal recognizes these issues and addresses them through the inclusion of opportunity costs into the default energy bids (DEBs) of RMR and CPM units. However, opportunity costs remain a complicated and contentious aspect of DEB calculations**.** Moreover, an aging resource may not be able to completely avoid a relatively high forced outage rate by limiting its hours of operation. Although not described in the draft final proposal, the ISO has explained that the tariff will provide for the ISO to set the DEB in a manner that will allow such resources to limit their operating hours without respect to whether the resources are use-limited. If the opportunity cost framework used to calculate DEBs proves insufficient to address these concerns, the CAISO should consider a unit-specific outage benchmark for such units, applying the same RAAIM framework but with a different reliability threshold target. Alternatively, a targeted performance metric could be negotiated that would focus on periods when a generator is most likely to be needed.

Finally, the MSC recommends that transmission planning that could affect the need for RMR designation recognize that the avoided cost of generation will include just the RMR unit's going-forward cost (including possible opportunity costs for land and salvaging components), and not the entire full-cost-based RMR compensation, which includes sunk costs, depreciation, and return on book value. Because that going-forward cost may be very different from the full cost, situations are possible in which a transmission investment that removes the need for RMR status would be less expensive than the cost of service based RMR compensation, but more costly than the RMR generator's going-forward costs. Consistent with the CAISO TEAM (Transmission Economic Assessment Methodology) philosophy that transmission planning should work towards minimizing social cost, the incremental rather than full RMR cost should be the basis of determining if a network upgrade is economic. Under such a scenario, the RMR unit owner could be offered compensation comparable to the projected transmission replacement cost, which could be well below that unit's cost-of-service.

II. Background: Backstop Capacity Procurement in the CAISO Market

In the CAISO footprint of California, policy for Resource Adequacy (RA) is overseen by the California Public Utilities Commission (CPUC) and the CAISO. Pending changes currently under consideration at the CPUC, the current policy imposes a bilateral requirement on jurisdictional Load Serving Entities (LSEs) to acquire and "show" RA capacity sufficient to meet the planning reserve goals of each respective Local Regulatory Authority (LRA) in which the LSE operates. The requirements include elements of systemwide (or "generic") capacity, local capacity—able to address reliability needs within a specific local reliability area—along with flexible capacity capable of meeting the relatively recent Flexible Capacity Requirement.

Ideally, the RA requirement would result in payments from LSEs to generation and other competitive resources that, combined with energy and ancillary service revenues, would be sufficient to support both ongoing resource operations and future investment in the level of resources required to meet the local regulatory authority's reliability target.[6] These resources, in turn, operate under a must-offer obligation intended to ensure that the capacity that is procured provides the services necessary to maintain reliability within the CAISO system. However, periodically, gaps or shortfalls in the RA process have made necessary interventions by the CAISO through alternative forms of backstop procurement that have evolved several times since the RA program began in 2006.

Briefly, these interventions can range in length from a single day – through a process known as exceptional dispatch – to monthly or annual contracts. Currently monthly and annual backstop arrangements are implemented either through the CAISOs Capacity Procurement Mechanism (CPM) or through a Reliability Must Run (RMR) contract. The conditions under which CPM or RMR might apply have evolved and blurred over time, and one goal of this initiative has been to establish a more rationalized framework in which the role of each type of agreement would be transparent.

There are at least four broad scenarios in which the bilateral RA market might fail to meet the CAISOs determination of reliability needs.

1. An LSE may simply fail to comply with its RA requirements. In the absence of a waiver granted by the CPUC (discussed below), the LSE would stand in violation of its obligation.[7] The CAISO has had authority to perform a solicitation of capacity to fill any such shortfall and those costs are assigned to the deficient LSE.

2. While all LSEs may comply with the letter of the RA requirements, the requirements themselves feature gaps such that even under full compliance, "collective deficiencies" remain. In other words, at least some of the RA that has been procured is of either the wrong type or in the wrong locations.

   A short-term version of this problem arises when periodic transmission outages require the CAISO to call on non-RA units through the exceptional dispatch (ED) process. In this case, the RA that was procured would have been sufficient but changes to the network force an unanticipated shift in local needs. If a non-RA unit is dispatched through ED, it becomes automatically eligible for a monthly CPM payment.

[6] While short-term market revenues, combined with an annual or monthly RA payment, may be too uncertain or volatile to support investment in and of themselves, in theory the prospect of annual capacity or RA requirements should provide incentives for long-term contracts in which LSEs procure a stream of annual RA from resources, either bundled with energy sales or on its own.

[7] These LSEs are required to pay a penalty in addition to the cost of the backstop procurement to fill the need created by their shortfall.

3. All LSEs may comply with the requirements set by a Local Regulatory Authority, but those requirements may be judged by CAISO to be insufficient to meet the mandatory requirements imposed by the North American Electricity Reliability Corporation (NERC).

4. The bilateral market may fail to clear in a competitive fashion. In other words, resources and LSEs fail to reach a mutually acceptable bilateral agreement, and the CPUC grants a compliance waiver to the LSE. This forces the CAISO backstop process to effectively impose the terms of the agreement. The failure of LSEs and resources to agree on a mutually acceptable price could in turn be attributable to either
    a. Excessive local market power on the part of the resource, raising RA prices to unacceptable levels, or
    b. Waivers to the local RA requirement granted by the CPUC (or other LRA) to LSEs because the price was deemed too high, despite reflecting actual going-forward costs of the marginal resource in the region.

The waiver process was adopted along with the local RA requirements in 2006, and at that time was viewed by the CPUC as "necessary as market power mitigation measure"[8] in the RA market. The general approach was to limit the price which LSEs would be obligated to pay for local RA by waiving compliance penalties if an LSE can demonstrate that, despite pursuing "all commercially reasonable efforts" to procure RA, the LSE either received no bids or received only bids above a waiver price threshold, then set at $40-kw-year.[9] The trigger price was not meant to be the only criterion considered, and it is our understanding that some local RA agreements have been approved at prices above this threshold.

Waivers are a blunt and imperfect tool for limiting the market power that can be created by local RA requirements. If the waiver price threshold is set too high, then firms may still be able to enjoy substantial rents if they possess local market power. If the waiver is set too low, the RA "market" becomes effectively a cost-based system set largely by the CAISO's backstop terms. A low waiver could, intentionally or unintentionally, result in price-discrimination among RA resources, where some high-cost resources are paid their costs, and others are capped at the waiver level. The existence of such price discrimination could deter even minor investments in going the forward costs of existing capacity, leading to inefficient exit and higher costs for power consumers. As we discuss below, a rationalized system would ideally reconcile the two primary tools for mitigating market power in this process: the waiver threshold at the CPUC as well as the soft-offer cap in the CPM.

One last important element in the backstop process is the prospect of the retirement of plants important for reliability needs. Prior to the recent February 22nd, 2019, CPUC decision, both bilateral RA requirements and CAISO CPM were either monthly or annual commitments. Some

[8] CPUC, D.06-07-031/ R.05-12-013, "Opinion on Local Resource Adequacy Requirements," p. 71. That decision also identified the aggregation of local capacity regions, as well as the CAISO backstop process as additional measures that would combat market power. It also expressed (p 71.) the expectation that local market power mitigation under the CAISO market redesign "would provide mitigation not only with respect to the exercise of market power in the CAISO markets, but it should also have a mitigating effect in the RAR bilateral contracting markets."

[9] CPUC, D.06-07-031/ R.05-12-013, p. 73.

plant owners, particularly those requiring new capital investments in order to maintain or improve their facilities, have stated that annual CPM, let alone monthly CPM payments, were not adequate to continue operations. In such cases, either a multiyear contract or increased annual payments would be necessary to prevent the retirement of the facility or to keep the resource temporarily in operation while network upgrades are made to eliminate the need to keep the resource in operation.

It is also important to recognize that the California policy and market landscape is continuing to experience dramatic changes. The rapid proliferation of community choice aggregators has transformed wholesale-retail interactions, with the implication that IOU procurement, overseen by the CPUC, will no longer dominate the buyer side of the wholesale market, potentially increasing competition in generation procurement. California's effort to meet load with higher levels of renewable electricity production will increasingly shape future generation investment, reliability needs, and short-term market outcomes. In the face of these changes, RA policy at the CPUC is continuing to evolve. While the current bilateral requirement remains in place - with more extensive forward commitments – the CPUC has indicated that further changes are quite likely in future years.[10]

III. The CAISO RMR/CPM Proposal

The CAISO's proposal covers a wide variety of aspects of backstop procurement, and we will not comment on all of them. In this section we summarize what we understand to be the key structural elements of the CAISOs proposed approach to backstop procurement and the logic behind those elements.

III.A. Roles of CPM and RMR

First, the CAISO is taking steps to clarify and formalize the relative roles of RMR procurement and the CPM. Going forward, RMR will be reserved for units that both fill a critical reliability need and are at risk of retirement (ROR) while all other backstop actions will flow through the CPM process.[11]

III.B. Risk of Retirement

One aspect of this codification of roles is the process through which the risk of retirement, and reliability need, is determined. Several stakeholders have expressed concerns about the credibility of ROR claims.[12] The perspective of these stakeholders is that a plant that would not otherwise seek to retire or mothball, might claim it is willing to do so because of what they perceive to be favorable RMR terms. At the same time, most stakeholders recognize that market conditions

[10] *Commissioner Blog: Keeping the Lights On*. www.cpuc.ca.gov/cpucblog.aspx?id=6442460494&blogid=1551

[11] *Draft Final Proposal*, op. cit., p. 14.

[12] See, for example, CAISO Department of Market Monitoring, *Comments on the Second Revised Draft Proposal*, Jan. 2019. Public Advocates Office, California Public Utilities Commission, *Comments on the Draft Final Proposal*, Feb. 2019. Pacific Gas & Electric Co., *Comments on the Draft Final Proposal*, Feb. 2019

can change such that the continued operation of a resource can become economic and reduce the cost of meeting load. In addition, it is appropriate that resources that provide essential reliability services receive higher compensation than resources that do not provide those services when they are on the margin. Since the CAISO does not have markets for all of these reliability services, there is a potential for inefficient exit absent other compensation mechanisms.

The CAISO proposal recognizes these concerns and relies upon three mechanisms to mitigate the possibility that resources who do not plan to retire would use the threat of retirement to receive a payment greater than that available through the market or through CPM.

First, the CAISO will require legally binding affidavit from a corporate officer stating that

> "the resource will not remain in service and that the decision to retire or mothball is definite unless some other type of ISO procurement of the resource occurs, the resource is sold to a non-affiliated entity, the resource receives some other contracts, or the resource enters into an RA contract."

The CAISO notes that it will have the right to refer the firm to FERC if it determines that the affidavit is false, misleading, or otherwise constitutes an effort to game the RMR process.[13]

Second, if an RMR unit requires going-forward capital investments, such investments would be reimbursed for only an annualized "sliver" of going-forward investment costs, rather than receiving the full amount of the new investment up front. If an RMR unit returns to the market, it would not be eligible to recover any further slivers of that investment.[14] Hence if market conditions change and the resource remains in operation after termination of the RMR agreement, no further reimbursements would be received. Conversely, if the unit retires when it is no longer needed for reliability, it will be eligible for a termination fee that compensates it for having made the investments necessary to operate under the RMR contract.[15]

Third, the process involves a degree of uncertainty that adds risk to a strategic claim of ROR. Since the CAISO's determination of a reliability need is made *after* the unit declares its intent to retire, not all units can be confident they would be offered an RMR contract once they make a retirement declaration. If a firm really didn't want the plant to retire, but only wanted an RMR contract, there is a risk that the CAISO would not find it necessary to award an RMR contract for the continued operation of the resource and would let the plant retire. If a plant doesn't retire after declaring an intent to retire, the CAISO proposes that it could be referred to FERC for strategically playing the RMR process. [16]

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[13] The proposal also modifies the timelines under which notifications would be made and establishes a publicly available list of units that have provided ROR notifications. Under the Draft Final Proposal, all units 45 MW or greater would be required to follow this process.

[14] *Draft Final Proposal,* pp. 18-19

[15] *Draft Final Proposal*, p. 19. The incurred capital cost, including interest, would be paid as part of a termination fee, but not a rate of return on the capital addition. The unit could return to the market after 36 months without having to repay this termination fee.

[16] *Draft Final Proposal,* p. 16.

Stakeholders have raised concerns that the RMR process can be initiated through notifications of either retirements or of temporary shut-downs (mothballing). Since a mothballing notice need only cover a finite, relatively short, period of time, the risk of such a notification is greatly mitigated. The concern is that a firm could use a mothball notification for one of its units to determine whether the CAISO would consider that unit to be critical for reliability needs

III.C. RMR and CPM Compensation

The CAISO proposes to continue the longstanding practice that a plant that receives an RMR contract will be paid its full cost of service, including a rate-of-return on the remaining book value of its capital stock. The plant would receive no net revenues from short-term energy and ancillary services markets. Those revenues would be used to offset first its variable cost, and then the other components of its cost-of-service payments. In essence the plant would become, for the term of its RMR contract, a traditional cost-of-service regulated resource.

The CAISO proposal envisions the CPM as an additional phase of an RA market process, rather than a full-scale regulatory intervention. Once a shortfall in RA capacity has been identified, the CAISO would first undertake a competitive solicitation process (CSP), in which resources with eligible capacity can make offers to supply the requested RA capacity on a monthly or annual basis.

Resources that make offers into the CSP are subject to a soft-offer cap, currently set at $75.68 per kW-year. Supply offers up to that level would not be subject to any regulatory review. If there were several units competing to supply RA capacity through the CSP, the CAISO would select the lowest cost offer, adjusted if necessary for the effectiveness of the plant in addressing the reliability need.

A resource is eligible to submit an offer above the soft-offer cap, but would be required to demonstrate that its going-forward fixed costs (GFFC) plus 20% exceeds the $75.68 soft offer cap. [17] Again, the CAISO would select the lowest cost offers to fill the RA need, but it is likely that it would only be taking offers above the soft-offer cap in situations where there are a limited number of high cost resources able to fill the specific RA need.

In contrast to the RMR compensation, units receiving CPM would be allowed to keep all short-term energy and ancillary service market revenues in addition to their CPM payments.

Several stakeholders have raised concerns about the level of the soft offer cap. The concern is that neither CPM nor RMR compensation will necessarily adequately mitigate the local market power of certain RA units. On the one hand, an older unit with local market power whose capital stock has been largely depreciated could find the soft-offer cap to be substantially above its analogous RMR payment level. On the other hand, it is possible that the CPM payment (based upon 120% of the estimated GFFC of a hypothetical unit) could be less than the actual going-forward

[17] For this purpose, its going-forward costs would be calculated using the same cost categories as used for the reference resource that sets the soft offer cap. These costs would include *ad valorem* costs (property taxes), insurance, and fixed operation and maintenance costs (DFP, p. 43).

costs for some high cost units and could therefore be insufficient to finance the necessary improvements to a unit that needs to make some going-forward capital investments or incur other costs not included in the identified going-forward costs. The expected level of energy market revenues, which are kept under CPM but surrendered under RMR may also be an important consideration for some units. We discuss these issues further in the following section.

III.D. RMR and CPM Performance Requirements Incentives

In addition to the compensation provided to RMR and CPM units, the other important dimension regarding backstop procurement relates to the timing and levels of performance that are provided by resources receiving RMR and CPM contracts. In this area the CAISO's proposal looks to utilize the standards and requirements applied to RA units acquired through the conventional, bilateral process.

All units the sell RA in California are subject to a must-offer obligation (MOO) that requires a unit either offer or bilaterally schedule its output into both energy and AS markets whenever available. In order to incentivize and reward availability, the CAISO applies a Resource Adequacy Availability Incentive Mechanism (RAAIM) to all RA units. The RAAIM applies penalties to units with poor availability performance during certain hours and rewards units with superior performance during those same hours. The CAISO proposes to apply the same MOO and RAAIM mechanisms to RMR and CPM units that is applied to RA units acquired through the bilateral process.

IV. MSC Comments on the CAISO Proposal

We agree with the CAISO's objective of defining distinct roles and pathways for RMR and CPM. Ideally, the RMR channel would be reserved for circumstances where there is little or no prospect that the market could provide a practical or competitive outcome. These instances could be thought of as situations in which the resources able to meet the reliability need possess material local market power in meeting the reliability need. We agree with the CAISO proposal that it is reasonable to address this market power by treating such instances as regulated services and to compensate resources providing these services according to traditional regulatory cost-of-service principles.

As discussed above, the mechanisms used to combat local market power in the RA market are both blunt and less than fully transparent. Given that both RMR and CPM partially function as elements of the overall scheme to mitigate local market power in California's RA markets, it is worth considering, for purposes of comparison, the results that a hypothetically idealized mitigation process--or perfectly competitive market--would produce. Given the current structure of the RA system, and the inherent challenges in mitigating RA in general, we are not arguing that these idealized outcomes are necessarily feasible at this time. Rather, those outcomes provide useful perspective for assessing the current proposal.

IV.A. RA and Market Power Mitigation

In theory, mitigation of local market power in RA would function somewhat like market power mitigation in energy markets. That is, resources would offer in their production (capacity in RA markets) at incremental cost and the market would clear at either the cost of the marginal unit or include some form of scarcity rent if scarcity is present.

In the RA context, resources would offer their capacity at their going-forward incremental cost, which might include some pro-rated cost of required new investment, less their expected, risk adjusted energy and ancillary service market net revenues. In a market with sufficient capacity, prices would clear at the incremental cost of the marginal resource. In a market in which there is a need for investment in new capacity, prices would clear at something resembling the cost of new entry (CONE) less energy and ancillary services revenues (net-CONE). Eastern ISOs strive to replicate such outcomes using capacity demand curves whereby prices rise gradually as reserve margins decline up to a price ceiling that is some specified multiple of Net CONE. Eastern ISOs also require at least some resources to submit mitigated bids in capacity market auctions.

Setting the exact form of these capacity demand curves can be contentious, but it is generally agreed that prices should fall somewhere between the incremental cost of the marginal (last) source of capacity and a multiple of net-CONE as the RA market approaches scarcity or near scarcity levels.[18]

For local capacity requirements served by "lumpy" capacity, it could be the case that a single, or small number, of existing units is sufficient to meet existing capacity needs, but the exit of any one of these units would trigger scarcity. In the extreme, this kind of scenario would represent a form of natural monopoly for this local RA service, where one unit is sufficient to meet the local needs on an ongoing basis. The market is not in scarcity if the existing resources remain in operation, but paying the incremental going-forward cost would be insufficient to recover the full average cost of the existing facilities. The CAISO RA design lacks a demand curve that would set the market price of capacity in this situation as is the case in Eastern markets.

It is useful to distinguish between the efficiency implications of capacity payments under such scenarios and the equity implications. The correct outcome from an efficiency standpoint would be to keep the essential plant in service. There is a range of payments that, in the short-run, would accomplish this. In the long run, new investment for meeting the local RA need should only be pursued if that investment were less costly than continued operation of the existing facility (accounting for environmental considerations).

[18]In the case of PJM's system, the demand curve was intended to result in capacity prices that would in the long run average out to net-CONE, assuming that additions of the type of generation underlying the CONE calculation would continue to be needed. Year-to-year variations between going-forward costs for existing capacity and scarcity levels that are defined as a multiple of net-CONE are expected, and would average out to something near net-CONE over the long term (B.F. Hobbs, M.C. Hu, J. Inon, M. Bhavaraju, and S. Stoft, "A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model," *IEEE Transactions on Power Systems*, 22(1), Jan. 2007, 3-11),

One last consideration is the potential for price-discrimination between new and incumbent sources of RA. We neither dispute nor endorse claims of such strategies as we have been unable to verify or refute them due to the lamentable lack of transparency in the RA market, but we can discuss the general implications of such strategies. Large LSEs can have an incentive to pay above-market prices for new resources if it results in lower costs for their entire RA portfolio. While this strategy can produce short-run savings for LSEs, it can lead to inefficient early retirement of existing plants and raise RA costs over the long-run.

In a 2010 opinion on CPM,[19] the MSC stated that

> *While this issue merits serious consideration, we feel that the CPM is too blunt an instrument to correct whatever market dynamics are at play. The fundamental potential for such pricing outcomes lies with the concentration of purchases within a few large LSEs. Extremely large LSEs can have the ability to procure capacity with an eye towards reducing RA prices regardless of the specific market rules for the RA process. This is true even in centralized capacity markets. Whether these LSEs have an incentive to do so, depends on their regulatory status and oversight.*

Most of this still applies today, although the changing landscape of retail supply in California could substantially reduce the market concentration of LSE load.

IV.B Risk of Retirement and RMR Compensation

The CAISO proposal views RMR as a form of regulated service intended for plants that are first, necessary for reliability; second, possess such material locational market power that their RA prices should be mitigated; and third, the payments available through CPM are insufficient to sustain their operations. The question remains as to how to make the determination of which plants would fall into this category.

We share the skepticism of some stakeholders that the affidavit requirement, along with limitations on the recovery of going-forward investments, would by themselves eliminate the possibility of a resources strategically claiming a need to retire. In addition, the ability of plants to provide notice of plans to mothball limits the scope of that plant's irreversible commitment if the CAISO analysis determines the plant is not needed for reliability. If the plant didn't really want to retire, and was instead testing the waters regarding its prospects for an RMR contract, the mothball notice can allow for the plant to return to the market, after a period of time, without fear of repercussions if the RMR contract is not forthcoming.[20]

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[19] Wolak, F., Bushnell, J. and B. Hobbs. *Opinion on the Capacity Procurement Mechanism and Compensation and Bid Mitigation for Exceptional Dispatch*, October, 2010, p. 8.

[20] The proposal does require an attestation that the plant would be out for the duration of its proposed mothball period. There could be repercussions, such as a referral to FERC, if a plant returned from a mothball designation early (Draft final proposal, op. cit., p. 16).

At the same time, we are not optimistic that the CAISO or some other external party would be well positioned to perform a credible economic test that could confirm or refute the financial viability of a specific plant. These are complicated business decisions that would be difficult for external reviewers to accurately second guess. We instead observe that, under the current proposal and our understanding of RMR contract terms, a unit that enters into RMR with potential local market power will not be allowed to return to the market until after that local market power is resolved through transmission upgrades or other changes to market conditions.

The CAISO RMR framework is focused on scenarios in which a plant is unable to cover its costs under current market conditions, but that framework does not explicitly discuss the implications of a future, predictable improvement in market conditions. It is worth noting that energy markets around the country have gone through periodic cycles before, and the framework the CAISO is seeking to establish should be robust to scenarios in which market conditions become more favorable for flexible conventional facilities in the future. These are conditions where such units can earn sufficient revenues from energy and ancillary service contracts to more than cover variable and going-forward costs, or its compensation under RMR contract terms.

Under the proposed framework, plants will be eligible for full cost-of-service payments if they provide notice of retirement (or mothball). There would be a much larger concern about "toggling" if the unit would have the option to return to market payments if and when market conditions change. An example of such a change would be where they are able to find a counterparty with which to sign a contract. This option bestows a right for resources with material market power to earn the "better of" market or cost-based remuneration. Such an option would increase both the appeal of RMR and the incentive for resource owners to claim a need for it.

From the perspective of mitigation of local RA market power, the concern would be that a pivotal and required RA resource might have the ability to choose either RMR or CPM-based compensation based upon whether it is willing to file a retirement notice. Since energy market revenues are retained under CPM but not under RMR, the attractiveness of CPM relative to RMR will fluctuate with energy and ancillary service prices. A hypothetical ability of a unit to choose to switch between CPM and RMR based only upon expected energy prices would be a form of toggling over which some stakeholders have expressed concern.

However, our understanding of the terms of RMR contracts is that the option over the form of compensation is *not* held by the resource, but rather is held by the CAISO. The CAISO has the ability to renew RMR contracts following similar regulatory principles each year.

Article 2.1 of the RMR Contract[21] states that

> (b) CAISO may extend the term of this Agreement for an additional calendar year as to one or more Unit by notice given not later than October 1 of the expiring Contract Year. CAISO may extend the term for less than a full calendar year as to

[21] California Independent System Operator. *Pro-Forma Reliability Must-Run Contract*, www.caiso.com/Documents/AppendixG-ProFormaReliabilityMust-RunContract-asof-Sep1-2018.pdf

one or more Unit but only if CAISO gives notice not less than 12 months prior to the date to which it proposes to extend the term.

Given this ability to renew RMR contracts, there is an important distinction between two situations:

- A situation in which the CAISO, through network upgrades or other changes, eliminates the local market power of a resource, and the resource wishes to return to the market because of changes in market conditions, and
- A situation in which the plant is still necessary, and therefore maintains its local market power, but wishes to return to the market because of changes in market conditions.

Under the proposal, our understanding is that if a plant is leaving RMR because the CAISO no longer needs it, it is free to return to the market (or retire), based upon its determination of its going-forward economic circumstances. At that stage, however, it would no longer possess the same degree of local market power and would no longer be considered to be operating in a natural monopoly circumstance.

We believe this feature of RMR compensation goes a long way toward addressing many of the concerns over the prospect of firms trying to strategically navigate RMR designations for their plants. It creates an incentive structure in which firms seeking (or exploring the prospects for) RMR arrangements forgo the option, as long as their plant remains necessary, to earn higher revenues should energy market prices increase. Firms should therefore be less likely to use such a process if they expected their continued operation to be economic at some date in the future. By maintaining an option to renew the RMR agreement under cost-of-service terms, the CAISO can ensure the plant does not retire if it continues to be needed. If it is no longer needed, the plant is free to re-enter the market, and its retirement decision would be based upon its assessment of going-forward costs against going-forward revenues. The implied multiyear commitment also assures the unit owner that it would be able to recover at least some of the costs of needed investments over several years.

Some stakeholders, such as the CPUC, object to paying full cost-of-service rates to RMR plants. As discussed above, from an efficiency perspective, there is no single "right" payment between the full cost-of-service and the going-forward cost (including new capital costs) of the plant, but there is a long-standing tradition of paying plants offering a regulated service their full cost of that service and of capping the revenues of resources possessing market power based on a regulated rate of return.

That said, we sympathize with the viewpoint that the capital cost component of the cost of service payment should not be driven by historic accounting choices of the owners of the plant if the plants was not historically subject to cost of service regulation. Plants that chose a long depreciation schedule for accounting purposes but recovered their return of, and on, investment in the market, for example, could potentially receive inflated cost of service revenues based on these historical accounting decisions which would yield a larger remaining book value. Indeed, such an RMR design could incent resource owners to choose inappropriately long accounting depreciation schedules in an effort to increase potential future RMR payments. We would therefore support a regulatory approach that does not *pro forma* link the cost-of-service payments to the depreciation schedule chosen previously by the unit owner, but instead determines an appropriate depreciation schedule based on its regulatory merits. The just and reasonable standard applies to RMR terms so a long depreciation period could be challenged if the implied costs are not defensible.

We note that concerns over strategic retirement notices, toggling, and the compensation levels of RMR plants are unlikely to produce short-run inefficiencies. If the plant is critical for reliability, the CAISO proposal ensures it remains in the market. It is possible that attempts to seek RMR compensation could lead to early retirement of a unit if it was not critical but would have been willing to stay in the market absent an RMR option. Such plants would likely be in a marginal economic circumstance to consider such a strategy, however.

If equity concerns over the potential for the strategic use of mothball or retirement notices are significant enough, the CAISO option could be broadened to include circumstances where the unit is no longer needed for reliability. In other words, the option for paying a resource at a cost-of-service rate can extend for as long as the buyer deems it desirable to do so. This would necessarily create difficult questions about who would make the decision to exercise such an option and what circumstances under which it should be exercised. The CAISO should not be put in a position of exercising contracts strictly for economic reasons divorced from its core mission.

IV.C. CPM Compensation

The positioning of the CPM framework is a difficult challenge as the CPM is a single tool that is the primary means to deal with several potential problems. The CPM is one of the only mechanisms for mitigating local market power in the RA market. It is also playing an important role as a true "backstop" to the bilateral RA process, one that must fill gaps in RA portfolios that, independent from any seller market power, result from the limits of RA requirement definitions or problems in the bilateral RA market itself, as described in Section II above.

The current CPM framework is deployed to fill several roles, including the short-term deployment of RA in response to unexpected outages of resources, and the backstopping of under-procurement. The CPM can also mitigate potential local market power by capping the amount local resources can earn if not procured through the RA market. The framework, however, does not seem well positioned to deal with a situation in which there is a shortfall in RA procurement within a local region because some generation may be in the position to be near-pivotal in some local capacity markets while being able to earn substantial energy revenues. The structure of CAISO RA requirements (for example, lacking a demand curve that is present in eastern capacity markets) create an inelastic demand for RA, and absent a waiver or other RA mitigation, such plants would possess market power in the RA market.

Under the CPM proposal the capacity payment to the RA supplier would be capped at the soft cap, or its actual GFCC + 20%. In this way there is a limit being place on how much rent a unit possessing market power in local RA can extract from the RA market. However, this cap does not account for the level of energy market revenues so might allow overall expected returns materially above the cost of service rate if that plant is able to earn large margins in the energy market. This would constitute a return above competitive market levels if there were adequate capacity to meet local area RA requirements, but that capacity was owned by a pivotal supplier. Our understanding is that the soft offer cap is based upon the GFFC + 20% of a hypothetical gas plant, and is a rough proxy for the marginal going-forward cost of capacity in the system. However, as discussed above, if the area is not short of capacity, the going-forward cost net of energy revenues (with some margin to cover costs and minor investments not included in the definition of going-forward costs) would be the appropriate benchmark. If the area is capacity deficient, the price should be based upon either some multiple of net-CONE or if greater, net GFFC.

Notwithstanding all of the above observations about the limits of CPM in balancing fair compensation to RA resources and the mitigation of market power, we do not see an obviously better alternative to this framework, at least within the current RA structure in California.

We do believe a new analysis about the *level* of the soft-offer cap is called for, and we understand that the CAISO is already scheduled to undertake such an initiative. Ideally the CAISO's soft offer cap would be reconciled with the thresholds used by the CPUC for granting waivers. Also, the CAISO should carefully consider the types of units likely to fall under CPM in the future, and ways to incorporate expected energy and ancillary services revenues into calculations of an appropriate soft-cap level.

More generally, the CAISO and CPUC may need to more extensively reevaluate California's approach to mitigating market power in the RA market. The California RA market could very well be moving in a direction where a dwindling number of conventional resources will be needed to fill critical reliability needs. Further bifurcation of RA both geographically and by unit characteristics (e.g. flexibility) could increase, or make more transparent, the market power of those resources that remain in the market. It may be advisable to explore more targeted forms of market power mitigation, such as the application of pivotal supplier tests, and to, the extent possible, incorporate other elements of RA market power mitigation as used in eastern ISOs.

IV.D. RMR and New Investment

The paying of full cost-of-service (including a return on sunk investment costs) could potentially create distortions in investment if not properly considered. A long-run distortion could arise if the full RMR payment is used as the benchmark cost of generation against which to compare alternative non-generation solutions to the reliability problem.

For example, assume a plant's GFFC and operating cost is $5 million and its full cost of service is $8 million. It is possible that a transmission investment (or other resource) could be added for $7 million. This would save RMR ratepayers money but also constitute an inefficient investment since the incumbent plant could provide the service for $5 million.

We propose that, before such investments are undertaken, the RMR plant be offered a payment comparable to the new facility cost, perhaps adjusted appropriately for the net value of energy and ancillary services provided. Such a payment would be lower than what it would be entitled to under the current proposal, but if it still exceeded GFFC the RMR plant owner should accept this lower "competitive" payment level and the allocation of investment resources would not be distorted. We acknowledge that it can be difficult to compare the relative values of transmission and generation (or storage) resources given that each type of resources provides its own distinct capabilities beyond a specific reliability need. The CAISO also cannot, and should not, control the procurement decisions of other market participants that can be strongly influenced by a host of state policy priorities. However, the CAISO does take the lead in the transmission planning process and should attempt to consider the distinction between the RMR compensation level and the going-forward cost of an RMR resource with regards to transmission specific investments.

IV.E. Performance Incentives for Backstop Resources

There are both efficiency and equity considerations to the performance requirement and incentive aspects of the CAISO's proposal. Since backstop procurement payments could be substantial, some stakeholders wish to ensure "ratepayers receive the most RA benefits from resources they pay for."[22] Efficiency considerations also arise, particularly with respect to RMR units that would retain none of market revenues earned by the units when they do operate. For these units in particular, it is clear that some kind type of performance incentive is highly desirable.

We do not agree with the perspective that applying a must-offer obligation to RMR units constitutes price-suppression. Even if these units remain operational because of unique, or natural monopoly circumstances, they are in fact operational and we believe it is appropriate that market outcomes reflect this fact as long as offers (DEBs) are based on reasonable accurate estimates of marginal costs. We therefore support the proposal's application of the must-offer obligation to both RMR and CPM units.

That said, it is important to recognize that the CAISO's process for calculating default energy bids (DEBs) can be problematic for some units, as highlighted by our recent opinion on Local Market Power Mitigation in EIM regions. Calculation of DEBs is particularly challenging when units may be subject to use limitations due to air-quality regulations or maintenance cost concerns. Such limitations may be relevant for units coming under backstop arrangements. In recognition of these concerns, the CAISO proposal includes provisions that would allow units to incorporate some of these availability costs into an opportunity cost component of their default energy bids (DEB).[23] In their comments on the Draft Final Proposal, NRG also argues that gas procurement costs can be mis-measured when calculating DEBs.[24]

For RMR units, this would be less a matter of fair compensation as these units would be able to file for cost-recovery (although NRG points out this could be a burdensome process), but there is a concern about the efficient utilization of plants if they are offered into the market at inaccurate costs. If use-limited units are over utilized due to a 17x7 must offer requirement, then they may become unavailable for reliability services during the very periods they were put under RMR to

[22] Public Advocates Office. California Public Utilities Commission. Comments on the Draft Final Proposal. February 22, 2019, P. 3.

[23] Draft Final Proposal, p. 23.

[24] NRG. Comments on the Draft Final Proposal. February 22, 2019, pp. 2-3.

address. Even if units can remain available, the costs required to make them available may not be worth the value a must-offer obligation provides.

There could also be legitimate concerns for aging units whose availability performance has historically lagged behind that of the averages used for RAAIM performance benchmarks. The performance incentive should incent a resource's operator to take all reasonable and prudent measures within their control to support the availability of the plant. If a plant's inherent characteristics make it difficult to meet RAAIM performance metrics, the RAAIM penalties would be increasing the cost of operating the plant beyond those that could be recovered by the operator, despite the operator taking all reasonable measures consistent with the level of operating and maintenance costs and cost of service payments it is receiving as part of its RMR compensation to maintain the availability of the resource.

As mentioned above, the CAISO acknowledges these issues, and addresses them through its calculation and inclusion of opportunity cost in DEBs. However, opportunity costs continue to be a difficult and somewhat contentious component of DEB calculations and neither the current nor proposed design appears to address opportunity costs used by resources to limit their operating hours in order to reduce their forced outage rate. Moreover, an aging resource may not be able to completely avoid a relatively high forced outage rate by limiting its hours of operation. Hence, it is uncertain whether the current DEB framework will produce DEBs that properly balance the costs of avoidable and unavoidable availability problems. If such cases arise, the CAISO could consider using a unit-specific performance benchmark based upon historic availability.

While conceding these are legitimate concerns, we observe that the CAISO has revised its approach to calculating DEBs under LMPM several times and is continuing to work to improve the representation of opportunity costs and maintenance costs in the process. One important difference is that normal RA units would be subject to DEBs only if they are found to possess local market power during a specific market period, while under this proposal, DEBs (which would include opportunity costs) would be used for RMR units during all hours.

We think that the CAISO's discretion can and should be deployed within the application of this framework. A distinction should be made for units coming under backstop to serve specific idiosyncratic reliability needs, as opposed to those filling more generic shortfalls in local, flexible, or system RA. Units in the former category would ideally be allowed to negotiate specific incentive criteria that are focused on performance of the unit where and when that specific reliability need is binding.

In addition, if the opportunity cost framework does not fully address these issues, units with severe or costly use-limitation constraints should be eligible to negotiate DEBs, and given the nature of the service they provide, RMR units should be given the benefit of the doubt in arguing for specific DEB formulas or levels.

If these measures prove insufficient, the CAISO could consider mitigating the bids of RMR units only during periods in which LMPM is binding for them. During other periods, the unit would be able to offer above its DEB in order to manage its use-limitations and other costs. If this approach were taken performance incentives would need to be devised to align the resource's incentives with market efficiency. While the dispatch of the unit may be based upon these market-based offers, the net revenue calculation for RMR units would still be based upon the DEB level of costs, for purposes of calculating the allowed operating costs to be recovered.