Revised Draft Final Proposal

Capacity Procurement Mechanism, and Compensation and Bid Mitigation for Exceptional Dispatch

September 15, 2010

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1. Executive Summary

The ISO is required by FERC to file a successor mechanism to the current Interim Capacity Procurement Mechanism ("ICPM") and updates to the price paid for and the bid mitigation applicable to Exceptional Dispatch at least 120 days prior to the March 31, 2011 sunset of the existing provisions. To this end the ISO initiated a stakeholder process with the posting of an issue paper on June 9, 2010.[1] This revised draft final proposal presents the ISO's proposed approach to the successor mechanism, called the Capacity Procurement Mechanism ("CPM").

The ICPM was conceived as an "interim" backstop procurement mechanism. Although the CPM will retain many features of the ICPM, the ISO proposes that it will be a permanent feature of the ISO's market structure, with provisions for updating certain details as needed, such as the price paid for backstop capacity and potentially some of the criteria for selecting the most effective available capacity. Like the ICPM and prior backstop mechanisms, the CPM would procure supply capacity that is not already designated as Resource Adequacy ("RA") capacity and that will, upon accepting a CPM designation, have obligations to be available to the ISO for scheduling and dispatch comparable to the obligations on RA capacity. In this sense both the new CPM and the interim mechanism it will replace may be viewed as limited backstop mechanisms that complement and supplement the capacity procured by load-serving entities ("LSEs") under the RA program.

Under the proposed CPM the ISO may procure capacity for the following needs and purposes:

1. To "backstop" RA procurement in instances where the aggregate procurement of RA capacity by LSEs is insufficient, either at the system level or in a particular local capacity area;
2. To address unexpected conditions that arise and that could not have been anticipated at the time the RA procurement was done (referred to as "Significant Events");
3. To retain and compensate for 30 days any non-RA capacity that was issued an Exceptional Dispatch (as required by the FERC-approved Exceptional Dispatch provisions); or
4. Following appropriate consultations with stakeholders, to financially sustain resources that are in danger of shutting down due to lack of sufficient revenues in the current year and that the ISO has determined through operational studies will be needed the following year.

Categories 1 through 3 above are a continuation of the ICPM and Exceptional Dispatch tariff provisions, whereas category 4 is new.[2] In all categories the CPM procurement would be for at least 30 days, and in categories 1 and 4 it may be for up to 12 months. In the case of a multi-month procurement under categories 1 and 4, the ISO will suspend the CPM payment for any month in which the CPM capacity or a portion of it is procured as RA capacity by an LSE.

[1] http://www.caiso.com/27b0/27b0eb0cf3e0.pdf.

[2] In the previous straw proposal the ISO said it was considering two additional types of need for which it wanted to use CPM: (1) to manage maintenance outages of transmission or generation, and (2) to backstop situations of sustained under-performance of intermittent renewable resources relative to their registered RA capacity quantities. Upon reviewing the existing ICPM provisions on Significant Events, however, the ISO realized that these additional circumstances are fully consistent with the existing provisions and do not require defining new procurement categories. The ISO therefore proposes to retain for the CPM the existing ICPM language on Significant Event procurement rather than add these types of need as new categories.

The ICPM also contains criteria for selecting among eligible resources in situations where a particular need may be satisfied by two or more eligible resources. For the CPM the ISO proposes to retain the ICPM criteria and add two additional criteria: (1) a preference for non-use-limited resources over use-limited resources, and (2) consideration of specific operational characteristics of the resources. Both of these new criteria are needed to enable the ISO to select the resource that will best meet the identified need and will be fully available over the 30-day CPM procurement period. Because an Exceptional Dispatch of non-RA capacity will trigger 30-day CPM procurement, the ISO will also modify the Exceptional Dispatch selection criteria to include item (1); no change is needed for item (2) as the existing criteria already allow for such consideration.

Under the current tariff, capacity procured under ICPM and through Exceptional Dispatch of units that select an ICPM designation is paid at the same rate. Accordingly, the ISO proposes to retain that consistency under the new provisions. The ISO proposes to base the pricing for both CPM and units on Exceptional Dispatch on the going-forward fixed costs of a reference resource rather than on a per-resource basis. As with the current tariff rules, the base ISO tariff rate ($55/kW-year in this proposal) will be based on the most recent California Energy Commission ("CEC") report on costs of generation in California.[3] As such, the new payment rate for capacity will be the higher of a resource's actual going-forward fixed costs as defined by the formula in the tariff, as filed with FERC, or $55/kW-year.

With regard to bid mitigation for Exceptional Dispatch, the ISO proposes to permanently extend the current bid mitigation approach because it has been found to be appropriate to address market power in the fairly limited set of circumstances in which it needed to be applied. The ISO also proposes to retain the option for suppliers to elect "supplemental revenues" compensation in lieu of CPM compensation.

One final issue addressed in this straw proposal is to remedy a gap in the current ICPM provisions, which pay ICPM capacity for the full 30 days of procurement even when the associated resource is unavailable due to a planned outage for part of that time. For the CPM the ISO proposes to calculate compensation on a pro rata basis to reflect the time that the CPM capacity is actually available and not compensated under an RA or other capacity mechanism such as an RMR contract or a prior CPM designation.

2. Stakeholder Process

The ISO has initiated this stakeholder process to create tariff provisions for a CPM and to update the pricing and bid mitigation provisions for Exceptional Dispatch. This revised draft final proposal will be discussed at a stakeholder conference call on September 22, 2010. This proposal incorporates refinements to the draft final proposal that was posted on August 16, 2010, based in part on stakeholder comments. The prior papers and stakeholder written comments can be found at http://www.caiso.com/27ae/27ae96bd2e00.html.

The schedule for this process is due to the expiration of the current ICPM tariff provisions on March 31, 2011. The pricing and bid mitigation tariff provisions for Exceptional Dispatch also expire on March 31, 2011. The FERC requires the ISO to make a tariff filing 120 days before the sunset date to prevent a lapse of these provisions. The ISO is planning to make the required FERC filing, based on the outcome of the stakeholder process, by December 1, 2010, for new tariff provisions that would become effective on April 1, 2011. The major milestones in the stakeholder process are listed below.

[3] www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

May 28	Issue market notice announcing start of initiative
June 9	Post issue paper
June 14	Post agenda and presentation for June 16 stakeholder conference call
June 16	Hold stakeholder conference call on issue paper
June 23	Receive stakeholder written comments on issue paper
July 15	Post straw proposal
July 20	Post agenda and presentation for July 22 conference call
July 22	Hold stakeholder conference call on straw proposal
July 30	Receive stakeholder written comments on straw proposal
Aug 16	Post draft final proposal
Aug 19	Post agenda and presentation for August 23 meeting
Aug 23	Hold stakeholder meeting on draft final proposal
Sep 3	Receive stakeholder written comments on draft final proposal
Sep 15	Post Revised Draft Proposal
Sep 22	Stakeholder conference call 1-3 pm
Sep 29	Stakeholder comments due
Oct 8	Hold MSC meeting
Oct 13	Post Draft MSC Opinion
Oct 18	Hold MSC conference call to adopt MSC Opinion
Oct & Nov	Work with stakeholders on tariff language (specific dates to be provided)
Nov 1-2	Present proposal to ISO Board of Governors
Dec 1	File tariff at FERC
Feb 1, 2011	Order issued by FERC (60 days after Dec 1 filing date)
Apr 1, 2011	Effective date of new tariff provisions

3. Introduction

The ICPM tariff provisions enable the ISO to procure "backstop" generation capacity, subject to similar obligations as Resource Adequacy ("RA") capacity, to maintain grid reliability if (1) load-serving entities ("LSEs") fail to meet RA requirements, (2) RA requirements are met, but procured RA resources are insufficient to meet local reliability constraints, (3) unexpected conditions, such as a major transmission outage, create the need to procure additional capacity over and above the approved RA capacity; or (4) the ISO requires capacity not covered by a RA, Reliability Must-Run ("RMR") contract or existing ICPM through issuance of an Exceptional Dispatch. Exceptional Dispatch describes a commitment or dispatch performed outside of the market software by an ISO operator in cases where unit commitments or energy dispatches made by the market software did not fully address a reliability or operational need. Certain Exceptional Dispatch bids are subject to bid mitigation. Resources subject to Exceptional Dispatch are eligible for bid cost recovery but cannot set market prices.

The current ICPM and Exceptional Dispatch are currently linked mechanisms in that non-RA[4] capacity is eligible for ICPM designation for "supplemental compensation"[5] in the event that they are committed or dispatched through Exceptional Dispatch. Moreover, the bid mitigation for non-RA resources subject to Exceptional Dispatch can be different from the mitigation applied to RA or ICPM resources depending whether non-RA resources elect ICPM compensation or

[4] "Non-RA resources" is used here to designate resources with capacity not incorporated in RA or RMR contracts, or ICPM designations. As implied in this sentence, the term "non-RA resources" includes those that are considered "partial" RA as well as those with no capacity contract at all.
[5] The supplemental compensation is to provide an additional revenue margin for non-RA resources that are also subject to bid mitigation justified as a contribution to fixed cost recovery.

supplemental compensation in the event of an Exceptional Dispatch. Those rules are explained further below.

The ICPM backstop procurement provisions, and the pricing and bid mitigation provisions for Exceptional Dispatch, expire on March 31, 2011, two years after the implementation of the ISO new market design. If the ISO believes that it needs to rely on backstop capacity services beyond this sunset date, FERC requires the ISO to revisit those tariff provisions in a stakeholder initiative so that revised provisions can be approved by FERC and implemented such that there is no gap in applicability.[6]

The final proposal that results from this stakeholder initiative will be presented at the November 1-2, 2010 ISO Board of Governors meeting as the ISO is required to file its successor to the ICPM and Exceptional Dispatch tariffs 120 days before March 31, 2011.[7]

The ISO conducted an extensive stakeholder processes to develop the current ICPM and Exceptional Dispatch tariff provisions. Background information on both the current ICPM and Exceptional Dispatch can be found, respectively, at http://www.caiso.com/1bc5/1bc5db284cc80.html and http://www.caiso.com/1c89/1c89d76950e00.html.

The ISO is not proposing a wholesale redesign of the core elements of the ICPM or Exceptional Dispatch tariff provisions going forward from April 1, 2011 because it believes that these provisions are working well and are justified within the existing parameters of the RA program and the ISO's reliability and operational needs. However, the ISO is proposing some revisions to the current tariff provisions.

The key scope of work for this initiative includes the topics listed below:

1. Determining the duration of the new backstop procurement mechanism, including whether the provisions should be open ended or have a specific sunset date.
2. Clarifying the scope of the existing backstop procurement authority.
3. Broadening the backstop procurement authority in one aspect to provide a mechanism to ensure that certain key resources that are not RA resources remain in the ISO fleet and available to the ISO and are not retired prior to the date at which the resource is needed to enable reliable operation of the system or until such time as the resource can be replaced by other capacity (for example, until the resource in question can be replaced with a new resource with a more modern technology, or replaced by a different resource).
4. Modifying the procurement criteria that would be used to select from among the pool of eligible non-RA resources to recognize operational characteristics that are needed for reliable operation of the system.

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[6] "While we will not direct the CAISO to initiate a stakeholder process by December 1, 2009, given prior Commission action, it should be clear to both the CAISO and its stakeholders that resources utilized for backstop capacity services must be appropriately compensated for their services and that the Commission will not accept a temporary lapse in such compensation. Therefore, if the CAISO needs to rely on backstop capacity services beyond the ICPM's proposed sunset date, in order to reliably operate its system, we expect the CAISO to make a timely filing with the Commission that will ensure the continuation of just and reasonable compensation for the services rendered." 125 FERC 61,053.

[7] "Thus, if the CAISO still intends to exceptionally dispatch these non-resource adequacy resources, we require the CAISO to file no later than 120 days prior to the sunset of Exceptional Dispatch mitigation and ICPM, a compensation proposal applicable to such resources that is consistent with the precedent established in the RCST, TCPM, and ICPM proceedings. Alternatively, the CAISO may revise the MRTU Tariff to clarify that non-resource adequacy resources will not be subject to Exceptional Dispatch." 126 FERC ¶ 61,150 (P247).

5. Establishing an updated price/compensation methodology for payments for capacity procured under the CPM and Exceptional Dispatch.
6. Examining whether to change the categories of bids subject to mitigation under Exceptional Dispatch and whether to extend the bid mitigation for the existing categories.

4. Background

The ICPM was conditionally accepted by FERC on October 16, 2008.[8] The ISO's November 17, 2008 compliance filing was accepted by FERC on December 18, 2008. The Exceptional Dispatch tariff provisions were conditionally accepted by FERC on February 20, 2009[9]. The ISOs compliance filings were accepted by FERC orders issued on September 2, 2009[10] and May 4, 2010.[11] FERC directed the ISO to file any extension no later than 120 days in advance of the sunset date of both Exceptional Dispatch pricing and bid mitigation and ICPM, which means the ISO needs to make a filing by December 1, 2010 for April 1, 2011implementation.

The ICPM tariff was approved by FERC as an interim measure in part because the California Public Utilities Commission ("CPUC") was conducting a proceeding to address long-term RA program issues, including the possibility of a capacity market. There was a concern that the design of the backstop mechanism not constrain efforts to develop the long-term RA framework. As a result, the ISO proposed that the ICPM tariff provisions automatically sunset, but with the ultimate goal to design a long-term backstop mechanism that is complementary to the long-term RA design. ISO management also noted that it expected to return to the Board of Governors at some point in the future with a proposal for a more permanent backstop mechanism to replace ICPM.

On June 3, 2010 the CPUC adopted a final decision in the long-term RA proceeding that leaves the current RA program essentially unchanged. The implication of this decision for the current initiative is that the provisions adopted here must be aligned with and complementary to the existing RA framework, and must be expected to remain in place indefinitely.

Based on experience with the ISO's redesigned market structure that went into operation on April 1, 2009, two important points are clear. First, the actual use of and costs associated with ICPM and Exceptional Dispatch have been far less than stakeholders anticipated in their comments at the time these provisions were filed at FERC. Since April 1, 2009 (17 months), there have been only 18 ICPM procurements, for a total of 638 MW, at a total cost of $2.5 million with no designation lasting longer than 30 days.

Second, the previous point notwithstanding, the ISO cannot simply allow these provisions to expire. To assure its ability to operate the system reliably under diverse system conditions, the ISO must have both a backstop capacity procurement mechanism and an exceptional dispatch mechanism as permanent features of its market and operating structure. Therefore, in light of FERC's filing deadline, the ISO must move forward on a stakeholder process to extend the ICPM and Exceptional Dispatch tariff provisions, which the ISO believes are generally working well, and address needed enhancements.

Finally, some stakeholders have argued in prior discussions of ICPM and Exceptional Dispatch that the ISO should define new ancillary service products or procurement mechanisms as a preferable approach for obtaining resource capacity with needed performance characteristics.

[8] 125 FERC ¶ 61,053 (2008), docket Nos. ER08-556-000 and ER06-615-020.
[9] 126 FERC ¶ 61, 150 (2009), docket nos. ER08-1178 and EL08-88.
[10] 128 FERC ¶ 61,218 (2009).
[11] 131 FERC ¶ 61,100 (2010).

The ISO has initiated a separate stakeholder process to undertake a comprehensive review of renewable integration market needs, including ancillary service products and new markets and market products. This initiative will draw on the results of operational studies[12] to consider what services the ISO needs to reliably operate the grid with renewable resources supplying 20 percent to 33 percent of the energy on an annual basis, with variable resources comprising the bulk of that energy, and how best to procure such services.[13]

However, the ISO has determined that this and other related initiatives do not eliminate the need for the present backstop procurement mechanism and Exceptional Dispatch initiative. First, the determination of additional ancillary services need and design changes cannot be completed and result in implementation of any new services or procurement mechanisms by the time ICPM expires on March 31, 2011. Second, even if and when new or redesigned ancillary service products and/or markets and products are implemented, the ISO will still need to retain a backstop capacity procurement mechanism and an Exceptional Dispatch mechanism to assure reliable operation of the system under a diverse range of grid conditions. Although the ISO believes that enhancements to ancillary service products and markets and market products should be designed with the intent of reducing the need to rely on such backstop mechanisms, it would not be prudent to completely eliminate the backstop capacity procurement mechanism or Exceptional Dispatch Mechanism. Therefore, the ISO believes that it has appropriately specified the scope and timeframe for the present initiative described in this draft final proposal.

5. Current Backstop Mechanism Tariff (ICPM)

The ISO has had a backstop procurement mechanism in place for many years. The first backstop mechanism was established following the 2000-2001 energy crisis, and imposed a Must-Offer Requirement on all generation resources. In 2006, California established an RA program with Must-Offer Obligations for certain RA resources, but all non-RA resources also continued to be subject to the FERC Must-Offer Obligation until the ISO's new markets were implemented. In 2006-2007, a payment was created for resources that were non-RA but were committed by the ISO under the FERC Must-Offer Obligation. The current version of the backstop mechanism, ICPM, has been in place since the start-up of the ISO's redesigned market structure on April 1, 2009.

5.1. Key Elements

The key elements of current ICPM are:[14]

1. The tariff provisions automatically sunset on March 31, 2011.
2. There are two types of circumstances that can trigger procurement under ICPM: (a) in advance of any RA compliance year or month, when the ISO determines based on the RA plans submitted by LSEs that there is a need for additional capacity at the system level or in a local area; and (b) during any RA compliance month when a "Significant Event" occurs that creates a need to supplement LSE RA procurement.

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[12] California ISO, *Integration of Renewable Resources – Operational Requirements and Generation Fleet Capability at 20% RPS* (August 31, 2010), available at http://www.caiso.com/2804/2804d036401f0.pdf.

[13] For example, non-generic capacity that can provide fast ramping capability and load following capability are two products that will likely be needed in the future to integrate large amounts of renewable resources.

[14] http://www.caiso.com/1bc5/1bc5db284cc80.html.

3. A Significant Event is defined as "a substantial event, or a combination of events, that is determined by the ISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis." The definition by necessity accords reasonable discretion to the ISO; therefore, FERC's approval of ICPM included a three-step procurement process and extensive ISO reporting requirements.
4. The term of payments to an ICPM resource varies from one month to up to 12 months depending on the RA requirement deficiency being remedied or the length of the significant event.[15]
5. Costs of the procurement are charged to the deficient LSE, or, if no one entity is at fault (i.e., "no fault"), then the procurement costs are spread to load in the Transmission Access Charge area or areas depending on the nature of the procurement.
6. The price paid to a resource for its capacity is based on the going-forward costs of a new conventional simple-cycle unit, as reflected in a draft June 2007 California Energy Commission ("CEC") report,[16] plus a 10% adder.[17] Using this methodology, the current ICPM offers a target annual capacity price of $41/kW-year and has no deductions for peak energy revenues or ancillary service revenues. Payment is subject to an availability factor and a level monthly shaping factor. A resource owner that believes that its going-forward costs are greater than $41/kW-year is able to file at FERC for a price higher than $41/kW-year, but the owner has to justify that price to FERC based on the same cost elements that are considered in setting the $41/kW-year default price. Resources get to keep all market revenues.
7. Participation in the ICPM by a resource is voluntary; a resource owner does not have to accept an ICPM designation when offered by the ISO.
8. The ISO has the ability to procure a portion or the entire capacity of a resource.
9. Criteria are provided for determining which resource would be selected for an offer of an ICPM designation when there are multiple resources that could fulfill the need for the capacity. In the event there is a tie among qualified resources, the ISO can use a random selection mechanism.
10. Extensive reporting requirements are included to ensure that all ICPM procurement is transparent to the market and stakeholders and regulators are informed on how well RA resources, by themselves, are meeting the various operational needs of the ISO.

[15] Note that a resource could receive an ICPM designation for less than 30 days (one month) if a non-RA resource was procured under ICPM during one month (say on January 20) but that same resource was previously procured by an LSE as an RA resource for the upcoming month of February. The ISO tariff provides that the resource would be paid an ICPM payment for only 12 days (from January 20-31).

[16] June 2007 California Energy Commission Draft Staff Report, Comparative Costs of California Central Station Electricity Generation Technologies

[17] Going-forward costs are the core fixed costs that a generation unit needs to make itself available for operation for the term of designation, but do not include such elements as return on investment. Going-forward costs are defined here as the sum of fixed operations and maintenance costs, ad valorem costs, and administrative and general costs. A 10% adder is in-line with previously approved adders and, among other things, will encourage LSEs to not simply rely on the ICPM backstop mechanism to meet their RA requirements.

5.2. Procurement to Date

ICPM procurement can occur in any of three ways: (A) procurement to backstop RA programs; (B) procurement to address a Significant Event; or (C) an Exceptional Dispatch issued to a resource for the use of its non-RA, non-RMR or non-ICPM capacity that triggers an ICPM capacity payment. ICPM procurement to date is shown in Table 1 below.

Table 1
ICPM Procurement – March 31, 2009 to September 15, 2010 (17 months)

#	Procurement Date	Resource Name	MW	Duration	Reason	Actual Cost
A. Procurement to Backstop RA Programs						
N/A	N/A	N/A	0	N/A	N/A	$0
B. Procurement to Address Significant Events						
N/A	N/A	N/A	0	N/A	N/A	$0
C. Exceptional Dispatch issued to Resources for use of Non-RA capacity that triggered ICPM Payment[18]						
1	4/21 - 5/20, 2009	Yuba City Energy Center	1	30 days	Dispatch above RMR cont.	$3,892
2	6/20 - 6/30, 2009	Humbolt	15	11 days	Outage of RA unit	$21,403
3	8/2 - 8/31, 2009	Mountain View	2	30 days	Outage of RA unit	$7,783
4	8/2 - 8/31, 2009	Mountain View	2	30 days	Local transmission outage	$7,783
5	8/7 - 9/7, 2009	Humbolt Mobile	5	30 days	Local transmission outage	$19,458
6	8/20 - 9/18 (2009)	Balch	1.5	30 days	Local transmission outage	$5,837
7	10/13 - 11/11, 2009	Creed Energy Center	48	30 days	Forced outage of transmission line	$186,796
8	10/13 - 11/11, 2009	Feather River Energy	1	30 days	Dispatch above RMR cont.	$3,892
9	10/13 - 11/11, 2009	Gilroy Energy Center	46	30 days	Local transmission outage	$179,013
10	10/13 - 11/11, 2009	Goose Energy Center	48	30 days	Forced outage of transmission line	$186,796
11	10/13 - 11/11, 2009	King City Energy Center	44.6	30 days	Forced outage of transmission line	$173,565
12	10/13 - 11/11, 2009	Lambie Energy Center	48	30 days	Forced outage of transmission line	$186,796
13	10/13 - 11/11, 2009	Wolfskill Energy Center	46	30 days	Local transmission outage	$179,013
14	1/5 - 2/3, 2010	El Segundo	20	30 days	Local transmission outage	$77,832
15	4/30 - 5/29, 2010	Delta Energy	127	30 days	Local transmission outage	$494,192
16	7/18 - 8/16, 2010	Yuba City Energy Center	1	30 days	Dispatch above RMR contract	$3,892
17	8/17 – 9/15. 2010	Huntington Beach 3	91	30 Days	Transmission Outage	354,134
18	8/24 – 9/22	Huntington Beach 4	91	30 Days	Generation Outage	354,134
	Totals		**638.1**			**$2,446,211**

[18] Note that several entities have elected the supplemental revenues compensation option. Resources for which their owner has elected the supplemental revenues option do not have an offer obligation, although the resource does have to respond to any subsequent Exceptional Dispatch instruction.

5.3. ICPM Compensation

The current tariff allows suppliers to elect prior to the start of each calendar year from two payment options: (1) a standard monthly ICPM capacity payment based on a fixed price of $41/kW-year or, (2) a resource-specific price based on actual verified costs. To date, all market participants have elected the incremental ICPM options at the fixed tariff rate of $41/ kW-year.

In addition, for Exceptional Dispatch, suppliers can elect prior to each month whether they want ICPM compensation or supplemental revenues compensation in the event a triggering Exceptional Dispatch occurs within the following month. In either case, the Exceptional Dispatch triggers a 30-day period. If a supplier elects ICPM compensation, the supplier will receive ICPM compensation for capacity subject to the Exceptional Dispatch that is not RA, RMR or ICPM (based on rules set forth in the tariff). As with non-Exceptional Dispatch ICPM, the compensation will be based on either $41/kW-year or the resource-specific price. The only difference is that for Exceptional Dispatch ICPM, the suppler will be paid $41/kW year until and unless a resource-specific price is in place. If a supplier elects supplemental revenues compensation, the resource will be eligible to be paid as bid of Exceptional Dispatches within the 30-day period subject to a revenue cap that is calculated based on the revenues above what the resource would be paid if the resource were subject to bid mitigation. The supplier can retain such revenues up to the cap, which is the ICPM payment the resource would otherwise be eligible to be paid.

6. Current Exceptional Dispatch Tariff

Like ICPM, some of the pricing and settlement rules, including market power mitigation, for Exceptional Dispatch will terminate on March 31, 2011. Hence the ISO has to determine whether, and if so, how to extend these rules. The tariff authority of the ISO to engage in Exceptional Dispatch as needed for system reliability and to resolve operational issues is not in question, but FERC has required the ISO to examine measures to reduce the use of Exceptional Dispatch, or, possibly, to create a new product. Whether such market design changes are necessary to reduce the need for Exceptional Dispatch is outside the scope of this final draft proposal; the focus here is on the bid mitigation and pricing issues that remain for resources under Exceptional Dispatch. Additional information on the ISO's stakeholder initiative to work with stakeholders on ways to reduce the use of Exceptional Dispatch can be found at the following web site: http://www.caiso.com/1c89/1c89d76950e00.html.

To the extent that specific pricing rules are needed for types of Exceptional Dispatch, there are two general issues:

- How resources that are non- or partially-RA, including any backstop capacity procured by the ISO, are compensated for their non-RA capacity if committed by the ISO to support system reliability (either through ICPM payments or so-called "supplemental revenues") and
- Whether energy bids for resources dispatched under Exceptional Dispatch should continue to be mitigated in certain circumstances.

6.1. Overview

Exceptional Dispatch tariff authority provides the ISO with the capability to manually commit and/or dispatch resources (generation and participating loads) that are not cleared through the market software but are needed to maintain reliable grid operations. Exceptional Dispatch also is used for various other functions that require a resource to be dispatched outside of a market schedule. These are manual instructions to generators (or participating loads) can be for forced start-up, forced shut-down, operation at minimum operating level, incremental energy or decremental energy.[19] Exceptional Dispatch can apply to all types of units in the ISO system, including those with an RA contract or ICPM designation and hence have a must-offer requirement into the ISO markets), RMR units, and resources that do not have any of those contracts or designations.

Typically, an Exceptional Dispatch is required to address unanticipated conditions as well as transmission constraints or generating unit operating constraints that are not captured in the models used in the Integrated Forward Market, the Reliability Unit Commitment or the Real-Time Market but needed for system reliability.[20] A detailed description of practices and rules for Exceptional Dispatches is provided in a *Technical Bulletin* posted on the ISO's website.[21]

Exceptional Dispatch is also an action taken by operators for the following reasons (see Section 34.9 of the ISO Tariff in Attachment 1):

- Perform Ancillary Services testing,
- Perform pre-commercial operations testing for Generating Units,
- Mitigate for Over-generation,
- Provide for Black Start,
- Provide for Voltage Support,
- Accommodate Transmission Ownership Rights or Existing Transmission Contract Self-Schedule changes after the Market Close of the Hour-Ahead Scheduling Procedure, and
- Reverse a commitment instruction issued through the Integrated Forward Market that is no longer optimal as determined through Residual Unit Commitment.

Under current market settlement rules and software, if a resource is needed by the ISO and the resource is started up or required to continue to operate through an Exceptional Dispatch, it will be guaranteed to be paid its start-up and minimum load bids through the bid cost recovery process. If a unit receives an Exceptional Dispatch for any additional incremental energy (above minimum load), this will be settled outside of the market clearing function (i.e., will not set locational marginal prices). If not subject to mitigation, any such Exceptional Dispatch for incremental energy will generally be paid the higher of: the locational marginal price at the resource's location; the resource's energy bid price; or the resource's default energy bid.[22] Bids subject to mitigation will generally be paid the higher of the resource's default energy bid or locational marginal price at the resource's location, unless the resource's bid price is less than its default energy bid, in which case the resource is paid the higher of the resource's energy bid price and the locational marginal price at the resource's location.

6.2. Mitigation of Bids

The ISO's original design for the new market did not include Exceptional Dispatch bid mitigation provisions. Over the period 2008-2009, the ISO made the case that due to uncertainties in the use of Exceptional Dispatch, and to mitigate potential market power when only a certain resource or a limited number of resources could be dispatched through Exceptional Dispatch to

[19] Resources with Participating Generator Agreements or Participating Load Agreements have an obligation to comply with Exceptional Dispatch. Resources under a Metered Sub-System Agreement only have this obligation during an emergency. Other resources do not have an obligation.
[20] Section 34.9 of the tariff sets forth the ISO's authority to issue Exceptional Dispatches. .
[21] ISO Technical Bulletin on Exceptional Dispatch, http://www.caiso.com/23ab/23abf0ae703d0ex.html.
[22] There are certain exceptions to this pricing for Exceptional Dispatch issued to perform ancillary services testing, to perform PMax testing, or to perform pre-commercial operation testing.

resolve a particular constraint, bids dispatched through Exceptional Dispatch should be subject to mitigation in defined conditions. FERC approved the bid mitigation rules discussed below.

The current rules for mitigating energy bids that are dispatched through Exceptional Dispatch are designed to address market power in two fairly limited circumstances:[23]

- Exceptional Dispatch to mitigate congestion on transmission paths deemed to be non-competitive under the competitive path analysis conducted by the ISO's Department of Market Monitoring; and
- Exceptional Dispatch related to "delta dispatch" procedures.

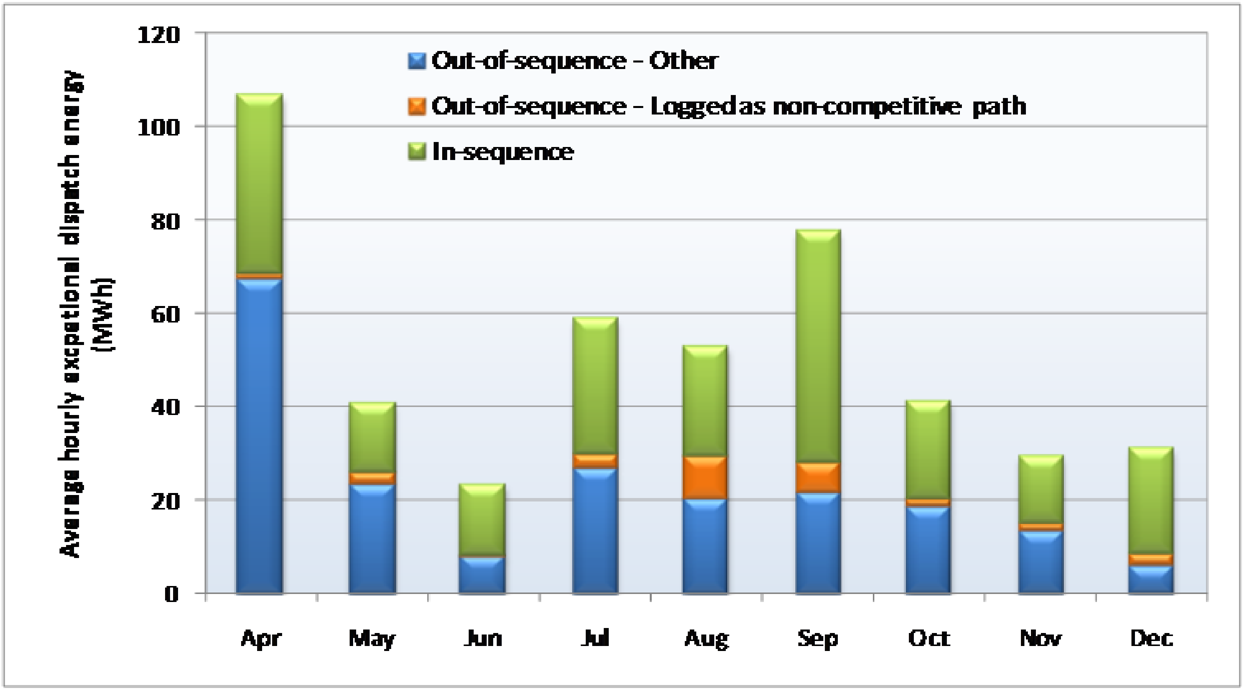
As discussed in the next section of this proposal, partial or non-RA resources subject to bid mitigation when being dispatched through Exceptional Dispatch are provided with additional revenues. The method through which a resource receives these additional revenues depends on whether the market participant has chosen to receive "supplemental revenues" or ICPM compensation for the resource in the event the resource is dispatched through Exceptional Dispatch.

The specific methodology currently used to mitigate bids that are dispatched under Exceptional Dispatch depends on the payment option the market participant has chosen for the resources.[24] If the supplemental revenues option is chosen, then the resource's bid price in individual hours is not mitigated and exceptional dispatches generally are settled at the higher of the resource's bid price, default energy bid or the locational marginal price at that location. The amount of supplemental revenues the resource can earn in any 30-day period is capped at the amount of what it could have earned through an ICPM capacity payment (if the market participant had elected ICPM rather than supplemental revenues for the resource).

If a resource does not choose supplemental revenues, then exceptional dispatches are generally paid the higher of the resource's default energy bid or the locational marginal price. If the bid for the resource is less than the resource's default energy bid; however, the resource is paid the higher of the bid for the resource or the locational marginal price.

Exceptional Dispatch subject to bid mitigation has been a relatively low portion of all Exceptional Dispatches. The following chart summarizes average hourly Exceptional Dispatch energy during 2009.[25] As shown by the chart, the vast amount of energy dispatched through Exceptional Dispatch has been for reasons other than to mitigate congestion on non-competitive transmission paths ("Out-of-sequence – Other" on the chart), or has been dispatched from resources with a bid price less than the locational marginal price ("In-sequence" on the chart). These categories are not subject to mitigation. Only a very small portion was dispatched from bids above the locational marginal price to resolve congestion on non-competitive transmission paths (and consequently subject to bid mitigation). These amounts are shown as "Out-of-sequence – Logged as non-competitive path" on the chart.

[23] Start-up and minimum load costs for resources committed at minimum load through exceptional dispatch are the same costs as used for in-market dispatches that are registered in the ISO master file. These costs are capped at 200 percent of actual costs.
[24] Market participants can elect to either receive an ICPM payment or receive "supplemental revenues" for a resource dispatched under Exceptional Dispatch.
[25] From ISO Department of Market Monitoring Annual Report on Market Issues and Performance 2009, page 4.16, http://www.caiso.com/2777/277789c42ac70.html .



6.3. Exceptional Dispatch Compensation

"Non-RA resources" is used here to designate resources with capacity not incorporated in RA, RMR contracts, or ICPM designations.[26] Such resources may be committed and dispatched through Exceptional Dispatch into their non-RA capacity. The intention behind the supplemental revenues compensation is to provide non-RA resources with a contribution to their long-term fixed costs, given that the ISO could be utilizing their non-RA capacity for reliability reasons and mitigating the bids used for Exceptional Dispatch.

The supplemental revenues compensation currently takes two forms. Prior to the start of each calendar month, market participants must elect for non-RA resources whether they want to be compensated for their non-RA capacity, in the event of an Exceptional Dispatch, through either:

- **Supplemental Revenues:** Bid-based energy payments ($/MWh) that are not subject to the same bid mitigation rules as other units dispatched under Exceptional Dispatch (or those dispatched through the ISO markets), but subject to a cap on the supplemental revenues that can be earned by a resource, as defined below; or
- **ICPM payments**: Non-RA capacity dispatched under Exceptional Dispatch may be eligible for an ICPM designation and resulting capacity payment ($/MW) provided on an "incremental" or "as-used" basis.

Resources eligible for the incremental ICPM designations either accept the current ISO tariff rate for ICPM of $41/kW-year or make a higher offer based on going forward costs, subject to approval by FERC.[27] These two optional methods for supplemental revenue compensation

[26] As implied in this sentence, the term "non-RA resources" includes those that are considered "partial" RA as well as those with no capacity contract at all.
[27] See ISO tariff Section 43; also Reliability Requirements Business Practice Manual section 7.3.5.2.

impose different obligations on the resource and have different pricing and revenue properties, which are discussed extensively in the tariff and Technical Bulletin on Exceptional Dispatch.[28]

Most resources have elected the incremental ICPM designations. The total cost to date of such supplemental compensation is shown in Table 1 of this proposal.

7. Revised Draft Final Proposal

7.1. Changes to Draft Final proposal

The ISO has revised the following sections to address stakeholder comments and discussions from the August 23, 2010 stakeholder meeting.

- Stakeholder Process – Added dates for development of an Opinion from the Market Surveillance Committee ("MSC").
- Procurement Authority – Provided greater detail on CPM procurement for maintenance outages and sustained reduction of energy output from intermittent resources.
- Procurement of Capacity for Resources at Risk of Retirement – Provided response to comments suggesting ISO authority is duplicative of CPUC General Order 167 Operating Standards 22-25 and RMR authority.
- Compensation of CPM Capacity – Provided additional details regarding CEC presentation and stakeholder comments.
- Carryover of Existing CPM Designations on April 1, 2011 – Provided new section describing how an existing ICPM designation could be carried over to CPM without issuing a new CPM designation.

7.2. Capacity Procurement Mechanism

For the CPM, the ISO proposes to extend the majority of the tariff provisions that are currently in effect for the ICPM, with a limited number of modifications as described in this section of the proposal. The proposed areas of change for the CPM design include:

- Duration of tariff provisions,
- Treatment of resources procured that later go out on planned outage,
- Adding criteria for selection of eligible capacity,
- Procurement of capacity at risk of retirement, and
- Compensation for CPM capacity.

In addition, as suggested by some stakeholders, the ISO has reviewed its existing tariff authority regarding backstop procurement to see if that authority already covers some of the types of uses of backstop procurement that were described in the straw proposal. Based on this review, the ISO has concluded that two of the types of procurement that were discussed in the straw proposal – procurement to allow certain planned transmission or generation maintenance to occur, and backstop for significantly less-than-planned output from intermittent RA resources – are already within the authority of the ISO through the current ICPM provisions (which are proposed to be retained as part of the CPM filing) and/or the Exceptional Dispatch provisions.

The first section below addresses the ISO's review of its existing tariff authority under ICPM and Exceptional Dispatch and its conclusion that certain types of procurement that were discussed in the straw proposal are already provided for in the current tariff. The sections that follow discuss the proposed areas of change from the ICPM tariff provisions to create the CPM.

[28] http://www.caiso.com/23ab/23abf0ae703d0.pdf.

7.2.1. Procurement Authority

As explained earlier in this proposal, the ISO proposes to retain from the ICPM the tariff provisions that enable the ISO to procure capacity under the following circumstances:

1. Backstop the RA program;
2. Address a Significant Event; and
3. Provide capacity payment for an Exceptional Dispatch of non-RA, non-RMR or non-CPM capacity.

In the straw proposal, the ISO discussed the procurement of backstop capacity to allow planned transmission and/or generation maintenance to occur. This situation could arise, for example, where a transmission outage has changed the topography of the electrical system and certain non-RA resources are now needed that previously were not needed to allow the planned outage to occur.[29] In practice, RA capacity is generally adequate to allow this type of maintenance activity to occur. However, there can be instances in which the procured RA capacity is not sufficient and the ISO has in fact experienced such. The straw proposal contemplated adding a separate ICPM category under which the ISO would procure capacity in the event a transmission or generator outage necessitates the need to maintain compliance with Reliability Criteria taking into account the expected duration of the outage. The ISO explained that in these instances, the ISO would procure additional capacity in advance of the planned maintenance for a 30-day period.

The straw proposal also discussed the use of CPM in situations where the output of intermittent RA resources is lower than their RA capacity values. As the amount of intermittent resources increases in the WECC, their contribution to load serving entities' RA capacity procurement will also increase. Qualifying capacity for these resources is calculated based on historical energy output, thereby resulting in a statistical estimate that may or may not be realized in any given day's real-time production. Unlike conventional capacity which can produce its full RA value unless it is on a forced or planned outage or de-rate, intermittent resource capacity is subject to the availability of its primary fuel source, i.e., the wind or sun. As such it is possible that for a significant period of time, due to circumstances beyond the resource operator's control such as a prolonger weather event, the intermittent resource is unable to provide energy reflecting its full RA capacity. This less-than-planned output for a significant portion of RA capacity could adversely impact reliability. Thus, in circumstances where the ISO expects the reduced production to persist – based on forecasted weather conditions, for example – the ISO may need to utilize the CPM provisions to procure backstop capacity.

Since posting the straw proposal, the ISO has reviewed its authority under the ICPM and Exceptional Dispatch provisions of its tariff and believes that both of the situations described above are already covered under the ISO's existing tariff authority describing procurement for Significant Event. Therefore the ISO is not proposing to create a new separate category of ICPM procurement for these types of events. The ISO continues to propose this in this revised draft final proposal.

In its February 8, 2008 ICPM filing to FERC, the ISO provided the following description of the Significant Event tariff authority.

[29] It is important to note that the type of procurement being discussed here is not in any way related to the "replacement rule" in the CPUC's RA requirements whereby under certain circumstances a load serving entity has to procure additional RA capacity to supplement an RA resource that will have an extended planned outage during the relevant compliance month. The additional RA procured under the CPUC rule will be "system" capacity (i.e., without any local capacity attribute), which may or may not meet an ISO need arising from a maintenance outage of transmission or of another generation resource.

b. Type 2 Procurement for ICPM Significant Events[30]

The CAISO recognizes that the RA program is the primary means by which resources are to be made available to meet the CAISO Balancing Authority Area operational requirements. The CAISO also understands that the Reserve Margins established by Local Regulatory Authorities should be set at a level that provides sufficient capacity by anticipating that Outages can and will occur. Nevertheless, the CAISO needs the ability to procure additional capacity under certain circumstances. Specifically, the CAISO must be able to address a single event, or a combination of events, that is determined by the CAISO to either: (i) result in a material difference from what was assumed in the RA program for purposes of determining the RA capacity requirements, or (ii) a material change in system conditions or CAISO-Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis. Accordingly, the CAISO proposes that it be able to designate ICPM Capacity to respond to an "ICPM Significant Event" which is defined as: A substantial event, or a combination of events, that is determined by the CAISO to either result in a material difference from what was assumed in the resource adequacy program for purposes of determining the Resource Adequacy Capacity requirements, or produce a material change in system conditions or in CAISO Controlled Grid operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis.

Examples of such "ICPM Significant Events" could include the following:
1. Loss of a facility, for any cause, that affects its capability, including but not limited to:
a. Loss of a local RA resource after annual LSE RA showing,
b. Lack of RA resources causing a shortage of capacity to meet required operating reserves (accumulated total, including ongoing scheduled and forced outages) after monthly LSE RA showing, or
c. Loss of a facility, CAISO Controlled or not, that affects the deliverability of RA, Reliability Must-Run Contract ("RMR") or other resource available to the CAISO, or affects the operation of the grid;
2. Grid study error, forecast changes, incorrect assumptions, bad data, or modeling inaccuracies, including, but not limited to:
a. An official change in the adopted Load forecast by the CEC after it has been used in RA showings by LSEs,
b. Error in load distribution factors,
c. Voltage or reactive resource modeling errors or resource changes,
d. Errors relative to deliverability of RA resources to load, or
e. Changes in non-CAISO Controlled Grid affecting previous assumptions;
3. Changes in applicable NERC or WECC reliability criteria or operating policies affecting the CAISO;
4. Insufficiency of RA units in RUC resulting in recurring use of non-RA units;
5. RUC and any subsequent Hour-Ahead Scheduling Procedure ("HASP") or real time run of the Security Constrained Unit Commitment ("SCUC") cannot

[30] ISO transmittal letter for ICPM tariff amendment filing, http://www.caiso.com/1f67/1f67d9d453990.pdf , page 23.]

converge by themselves with only RA units and requires manual addition by the CAISO of non-RA units; or
6. Change in federal or state law or regulation; court action; or imposition of environmental restrictions that affect the operation of resources

In its February 20, 2009 ICPM Order, FERC approved the Significant Event provisions and did not take exception or order any modifications or limitations to its application. FERC stated the following:

Determination[31]
*71. We accept the CAISO's proposed definition of "Significant Event" for the ICPM, which is the same as the definition we recently approved for the backstop capacity mechanism currently in place in California, the TCPM. In the order conditionally accepting the TCPM, we disagreed with some commenter's' claim that the TCPM Significant Event definition would result in the CAISO procuring TCPM capacity in excess of applicable reliability criteria.**51** As we explained in the TCPM Order, the Significant Event definition "is sufficiently restrictive in that it uses an objective, transparent baseline" and "it does not modify existing reliability criteria."**52** Further, we found that the authority to designate backstop capacity resources should not be tied to either operating reserve levels or a physical change in the electrical grid, because doing so could limit the CAISO's ability to procure sufficient capacity resources to meet existing reliability criteria.**53** The same rationale applies to use of this Significant Event definition in the ICPM context.*
72. We disagree that the ICPM is inconsistent with the deference given to local regulatory authorities under the CAISO Tariff. The CAISO is in a unique position to, in any given situation, assess whether resource adequacy resources are sufficient to meet existing reliability criteria, and to determine when insufficient capacity has been procured to maintain reliable grid operations. Additionally, we find that the ICPM Significant Event definition appropriately limits the CAISO's procurement of capacity to existing reliability criteria. Thus, the ICPM Significant Event definition should not permit the CAISO to change its current practices, nor should it interfere with the role of local regulatory authorities in the resource adequacy program. Rather, we find that the Significant Event definition is narrowly tailored to limit the CAISO's ICPM Significant Event procurement authority to situations when reliability is threatened and, therefore, provides the CAISO with an appropriate tool for maintaining grid reliability.

The ISO believes that the two types of CPM procurement needs discussed in this section are within the scope of the above definition of ICPM Significant Event and the accompanying list of illustrative circumstances that was filed for ICPM. First, a maintenance outage of a transmission line could constitute "a material change in system conditions … that causes or threatens to cause a failure to meet Reliability Criteria absent the recurring use of a non-Resource Adequacy Resource(s) on a prospective basis." Similarly, a maintenance outage of a significant RA resource could also constitute such a material change in system conditions. Even if the LSE procured additional system RA capacity under the CPUC replacement rule, a local RA outage, particularly if it occurs in combination with a transmission outage, could require the ISO to procure additional capacity under the significant event provision. Finally, given the statistical nature of the qualifying capacity determination for variable energy resources, it is possible that actual production of such a resource could fall below its RA capacity amount and be expected,

[31] FERC ICPM Order, http://www.caiso.com/235b/235b938e68860.pdf. 125 FERC 61,053 paragraph 71.

based on weather forecasts, to continue at this low output level for a number of days. This would constitute "a material difference from what was assumed in the resource adequacy program," and on that basis would be an appropriate use of the significant event provisions as currently structured.

The ISO also notes that the Exceptional Dispatch tariff provisions permit the ISO to Exceptionally Dispatch a resource, subject to specified conditions, during a System Emergency, or to prevent an imminent System Emergency, or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system Modeling (Tariff Section 34.9.1). Exceptional Dispatches can result in a 30-day ICPM designation.

Thus, based on further review, the ISO has concluded and confirms in this revised draft final proposal that it does not need additional categories of ICPM procurement to address these two types of potential CPM needs.

Maintenance Outages

The CPUC, SCE, TURN, Six Cities, CDWR, PG&E, NRG, SDG&E were supportive of the ISO procuring capacity through a Significant Event to allow maintenance outages to occur, whereas WPTF did not support this provision due to compensation being tied to the going-forward fixed costs methodology.

During the August 23, 2010 stakeholder meeting, participants were concerned how a Significant Event CPM designation would occur as compared to an Exceptional Dispatch instruction. For a maintenance outage, the ISO envisions a Significant Event declaration being different than an Exceptional Dispatch due to the timing of the notification. An Exceptional Dispatch is issued either as a unit commitment in the day-ahead market or an energy dispatch in the real-time market, whereas a Significant Event declaration would be issued a day or more in advance of the day-ahead market for the day when the outage is planned to begin, and would generally be designed to cover a longer duration outage.

Sustained Reduction in Output of Intermittent Resources

Stakeholders were less supportive of the ISO procuring capacity for a sustained reduction in output of intermittent supply resources. The CPUC argued that procuring for a loss of intermittent supply could increase costs by procuring capacity in excess of the planning reserve margin. SCE and NCPA disagreed with the ISO that Significant Event authority includes procuring for a sustained loss of intermittent supply and argued that the exceedance methodology for determining the qualifying capacity of these resources already builds in such output variability.

TURN, JP Morgan, NRG, CDWR, Calpine, Six Cities and RRI Energy supported procuring for a sustained loss of intermittent supply, with some parties adding that procurement should be infrequent, contain a detailed explanation of the event, and the ISO should seek to work with the CPUC to ensure a proper accounting of intermittent capacity.

The ISO disagrees with the claim that the exceedance methodology ensures that energy from intermittent resources will not fall below their RA capacity values. The exceedance approach is based on the number of peak hours that a resource exceeds a level of output. But, as a statistical point estimate, the exceedance value cannot preclude that resource producing a lower MWh amount that may be significantly below the resource's RA capacity value for an extended period of time, due to the fact that the primary energy resources (wind and solar radiation) depend on weather conditions not within the control of the resource's operator. Further, in establishing the exceedance methodology, the CPUC has set the exceedance level at 70% (as compared to 70%, 80% or 90% as was discussed as potential levels during the CPUC RA proceeding) so as to allow for a potential phase-in of the new exceedance methodology over time. When the methodology was proposed, the ISO recommended that the CPUC raise the value over time as the proportion of intermittent RA resources on the system becomes greater – perhaps having the CPUC decide to set the level at 70% initially but raising the level to 80% in the future, and potentially as high as 90% when the system has significant levels of intermittent resources. Given that the CPUC decided to set the value at only 70%, it may be possible that system reliability could be in jeopardy at some points in time due to sustained less than expected output. As the proportion of these resources in the supply fleet increases this concern becomes greater.

Based on data provided by the CPUC, wind and solar projects active in the queue represent approximately 20,000 MW of solar and 15,000 MW of wind installed capacity.[32] This significant amount of RA potential suggests that an over-reliance on qualifying capacity values could cause a temporary shortage of capacity in the event of a sustained loss of intermittent energy.

The two figures below were included in the ISO's August 31, 2010 paper, "Integration of Renewable Resources Study: Operational Requirements and Generation Fleet Capability at 20% RPS." The net qualifying capacity calculation is based on historical production during annual peak hours, but in any particular year, actual production on such days may be lower than the exceedance value. The two figures, also shown in the ISO's recent study of 20% renewable portfolio standard, show that wind production can reach below the net qualifying capacity in a sustained fashion in annual peak hours. At those times, the ISO may need to conduct backstop capacity procurement, depending on other system conditions and market participation. Figure 1 shows wind generation production during the historical peak hours in the July 2006 heat wave. The red dots indicate peak hours, showing that production during those hours was close to the daily minimum wind production. Figure 2 shows that in August 2010, peak load production varied substantially, but reached almost zero production in the peak hours on several consecutive days.

[32] http://www.cpuc.ca.gov/PUC/energy/Renewables/

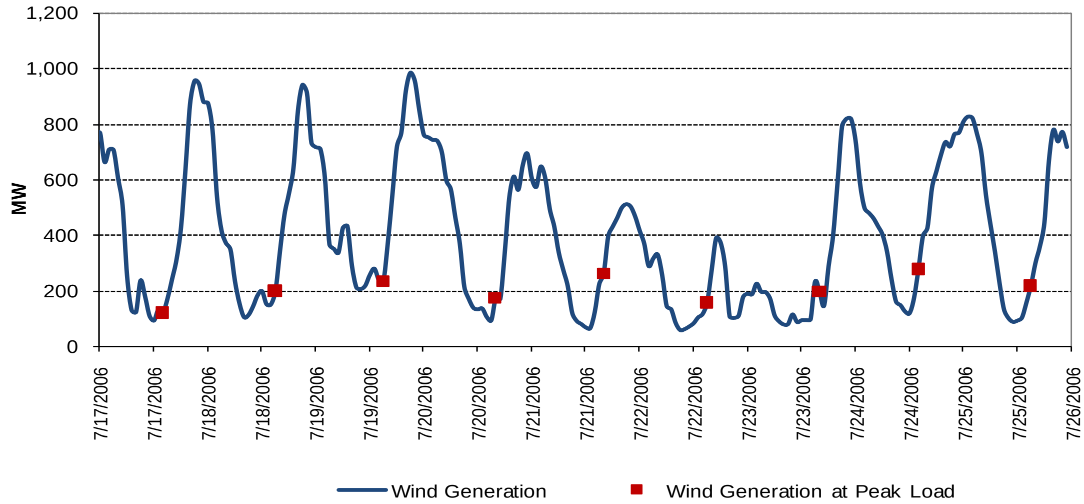


Figure 7: Wind Production during Summer Peak Hours in 2006

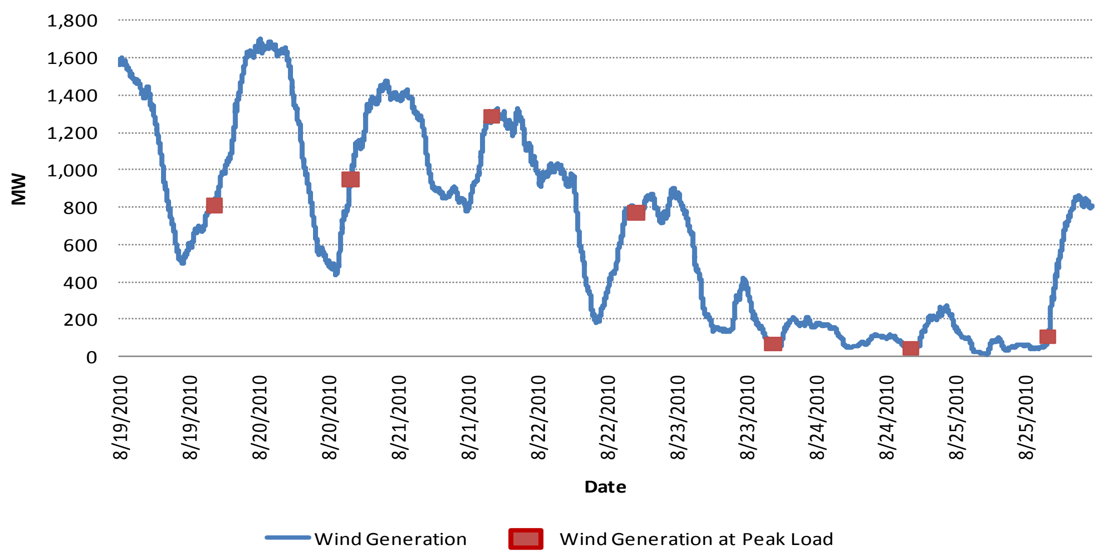


Figure 2: Wind Production during August Peak Hours in 2006

7.2.2. Duration of Tariff Provisions

PG&E, SCE, TURN, Six Cities, JP Morgan, SDG&E, NCPA and CDWR were supportive of the ISO extending the CPM backstop provisions without a sunset date. Some stakeholders suggested the ISO revisit the provisions on an annual basis to consider the impact on renewable integration efforts as well as updating the price every two years. Others, such as the CPUC and WPTF suggest a sunset date to perform a periodic review, Extending the backstop provision is a key element to this initiative and the ISO believes that a durable backstop mechanism is appropriate at this time. The ISO proposes to file the CPM and Exceptional Dispatch tariff provisions without a sunset date. Should the need arise, the ISO would consider updating design elements of the CPM and Exceptional Dispatch based on regulatory or market changes.

Stakeholders were nearly unanimous in their support for backstop authority without a sunset date with a biennial review to update the compensation.

The CPUC's recently issued June 2010 Final Decision on Resource Adequacy is little changed from the previous version.[33] The RA program secures capacity through a confidential bilateral negotiation process on yearly increments and is purchased based on local capacity requirements allocation studies performed by the ISO. The CPUC noted in its Final Decision at section 4.4.6.5 that the absence of a durable backstop mechanism is a shortfall of the current RA program.[34]

7.2.3. Treatment of Resources procured that later go on Planned Outage

Stakeholders have been supportive of this measure throughout this initiative. The CPUC, SDG&E, SCE, NCPA, Six Cities, TURN & PG&E all supported this proposal. Many Stakeholders suggested the ISO allow a resource owner to provide substitute capacity. The ISO maintains the position that planned outages are in the control of the resource owner and tit is not appropriate or necessary to create the additional complication of a substitution rule for this situation.

In the straw proposal the ISO proposed to add new language in section 43 of the tariff for reducing the capacity payment to a resource under a CPM designation that goes on a planned outage after the start of and before completing the 30 days of the CPM designation.[35] This element of the straw proposal received broad stakeholder support.[36] The ISO proposes to use the existing Capacity Payment Calculation currently in the ICPM tariff language[37], which excludes maintenance (i. e. planned) outages and prorate that payment amount based on the hours on planned outages.

The percentage by which the capacity payment will be prorated will be calculated by taking a ratio of 1) the sum of actual availability capacity, taking into account only planned outages, across all the hours the unit is designated to 2) the CPM Capacity MW * hours the unit is designated.

In the event that a CPM resource is out for only part of an hour, that hour's MW value will reflect the portion of the hour the capacity is available.

In the straw proposal the ISO also proposed that a resource owner could provide substitute capacity to avoid the reduction in capacity payment. The ISO now believes that it is not appropriate or necessary to create the additional complication of a substitution rule for this situation. The 30-day minimum for a CPM designation, including a CPM designation that is triggered by an Exception Dispatch, was established as an administrative rule to ensure that a resource is not relied upon for an ongoing need without fair compensation for its availability. If however, the resource owner chooses to take and the ISO grants a maintenance outage

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[33] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118990-03.htm#P543_15487.
[34] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118990-03.htm#P543_15487.
[35] http://www.caiso.com/27d9/27d9f7fb415d0.pdf.
[36] http://www.caiso.com/27c0/27c09fd63f70.html#27e781c443e30.
[37] See tariff section 43.6.1 and Appendix F, Schedule 6

(planned outage) for a portion of that 30-day period, the ISO believes the simplest and most appropriate course of action is to pay the resource for the portion of the 30 days that it is available.

7.2.4. Adding Criteria for selection of Eligible Capacity

Stakeholders were supportive of the ISO basing capacity procurement decisions on units capable of providing the service needed to address a reliability event. This included the CPUC, PG&E, SDG&E, RRI Energy. SCE only supported procuring for maintenance outages. Six Cities, TURN, NCPA, CDWR and JP Morgan were also supportive but cautioned against procuring only non-use-limited resources as some use-limited resources can also be made available to the ISO.

The ISO proposes to add two additional criteria to the existing ICPM criteria[38] for selecting from among eligible capacity for a CPM designation: a preference for non-use-limited resources, and an ability to select for needed operational characteristics. It is important to understand that with the addition of these new selection criteria, it is not the ISO's intent to expand the scope of triggers for CPM procurement. Rather, the intent is that once the need for CPM is triggered – by a shortfall in RA procurement, a Significant Event, an Exceptional Dispatch,[39] or the proposed new trigger discussed this proposal – the ISO may consider these additional criteria in determining which of the available non-RA capacity to select.

Regarding the non-use-limited preference, as noted in the July 22, 2010 stakeholder call, a key objective of the CPM is to obtain backstop capacity that will be available to the ISO in the day-ahead and real-time market timeframes throughout the procurement period, in a manner consistent with the must-offer obligations on RA capacity as specified in tariff section 40.6. Tariff section 40.6.4 also provides for certain types of resources to be classified as use-limited resources[40] and, upon such classification, to be exempt from the daily must-offer obligations applicable to non-use-limited resources. The ISO believes that a use-limited classification would substantially compromise the ability of the ISO to rely on the daily availability of the resource in the day-ahead and real-time markets to meet the need for which the CPM was invoked, and therefore proposes to amend the tariff to enable the CPM to preferentially procure non-use-limited capacity whenever possible. Adding this element to the existing criteria would not mean that the ISO cannot designate use-limited capacity. It would simply mean that this aspect would be one element that would be considered in selecting from among multiple eligible non-RA capacity.

For similar reasons the ISO proposes a second new criterion for selecting a resource based on its specific operational characteristics. This criterion and the previous one, when added to the

[38] See tariff section 43.3.

[39] Because an Exceptional Dispatch of non-RA capacity gets converted to a 30-day CPM designation, the ISO would also revise tariff section 34.9 to indicate that when an Exceptional Dispatch is likely to trigger a CPM designation, that priority be given to non use-limited resources. Section 34.9 already reflects consideration of the effectiveness of the resource when issuing Exceptional Dispatches generally. In the context of tariff section 34.9, "effectiveness" means the effectiveness of the resource to meet the reliability need. Accordingly, the ISO already has authority to consider operational characteristics of resources when making Exceptional Dispatch decisions.

[40] Appendix A of the tariff defines a use-limited resource as follows: A resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day.

criteria already specified with respect to ICPM, will enable the ISO to select the resource for a CPM designation that best meets the identified need.

Several stakeholders stated that procuring RA capacity to meet the planning reserve margin will ensure that sufficient capacity is available in situations involving planned maintenance, the loss of a generator and reduced intermittent output scenarios. Some also expressed concern that the expanded procurement authority discussed in the straw proposal (reframed in this proposal as applications of the existing Significant Event provisions) would encroach on the domain of the CPUC's long-term procurement planning process. The ISO believes that its proposed use of CPM for these circumstances would not be substantively different to today's use of ICPM to address short-term reliability needs that could not have been anticipated in the year-ahead or month-ahead RA procurement process, or loss of some RA, RMR or CPM capacity that creates a risk to reliable operation. Although the planning reserve margin in the RA requirement is an effective method for ensuring sufficient capacity based on static system conditions and the majority of maintenance outages, it does not guarantee sufficient capacity under all conditions. The ISO intends to continue cooperating with and working alongside the CPUC and local regulatory authorities to identify long-term RA needs, and believes that these short-term procurement scenarios can be used as a bridge and complement to the RA programs.

Stakeholders expressed concerns with the specific ISO proposal to use the CPM to address events of persistent under-performance of intermittent resources. Some stakeholders stated that such occurrences would indicate a deficiency in the RA counting rules for these resources and that a better way to handle such occurrences is to modify those rules. The ISO recognizes that reduced output from a variable energy resource in one year will be reflected in a reduction of the resource's qualifying capacity in subsequent years, and that under-performance may indeed indicate a need to modify the counting rules. But this is of no help in the current year if RA capacity is short due to persistent reduced output. No matter what method of counting is applied to valuing intermittent resources for RA capacity, the ISO could still be faced with an unanticipated short-term reliability need due to a sustained reduction in production.

Some stakeholders stated that before expanding the scope of CPM to these applications the ISO should provide more details and a determination of need. Although it cannot be known for certain that these needs will arise, such certainty should not be a precondition for establishing backstop provisions to be prepared for potential problems. In this regard the ISO believes that there is already sufficient evidence to support at least the potential for reliability issues to arise due to the circumstances described here. The ISO referred in the straw proposal to several studies showing a dramatic increase in the potential for real-time volatility and the operational flexibility the ISO will need in a 20 percent and a 33 percent renewable portfolio standard environment.[41] Although these RPS targets have not yet arrived, the ISO will need the flexibility currently in the CPM provisions to procure resources for the scenarios described in the straw proposal. To ensure reliability, the ISO needs to be proactive and cannot be reactive. To address any concerns about over-reliance on the CPM, the ISO's use of backstop procurement will be transparent and fully documented. The ISO will work closely with the CPUC and local regulatory authorities to address capacity needs and issues that arise so that the duration of ISO procurement can be minimized through LSE procurement wherever possible,

[41] IRRP stakeholder meeting on renewable integration requirement: http://www.caiso.com/2449/2449ea32303a0.pdf. and integration of renewable resources, http://www.caiso.com/1ca5/1ca5a7a026270.pdf.and www.energy.ca.gov/2010publications/CEC-500-2010-010/CEC-500-2010-010.PDF.

7.2.5. Procurement of Capacity at Risk of Retirement

In addition to the three existing triggers for ICPM (backstop the RA program, Significant Event, and Exceptional Dispatch), the ISO proposes for the CPM to add one additional trigger, essentially a new category of CPM procurement. The new category is needed to address the situation where a non-RA resource is not commercially viable for the coming year and is therefore intending to shut down, yet the ISO's operational studies indicate that this resource will be needed the following year. In this situation, the CPM designation for the current year is intended as a bridge to ensure that the non-RA resource will remain operable and be available when needed for the following year.

The first part of the scenario envisioned is that the resource in question ("resource A") was not awarded a bilateral RA contract for year 1 in any load serving entity's annual RA showing, while at the same time the ISO did not identify any deficiency, individual or collective, in the annual load serving entity RA showings for year 1 that would trigger a CPM designation for resource A. Thus resource A appears not to be needed for year 1.

However, as the ISO performs technical assessments looking one more year ahead to year 2, changing system conditions (such as the interconnection of additional intermittent renewable resources, retirement of a once-through-cooling generator, or a major transmission construction project that will impact grid operation for a major portion of year 2) indicate that resource A will be needed, either for its locational attribute or its operational characteristics, during year 2. Furthermore, there is no new generation under construction that could be in operation in time to substitute for resource A in year 2, nor is there sufficient time to develop a new generation project to meet the same need.

The next part of the scenario is that resource A will not be commercially viable in year 1. It does not have either an RA contract or a power purchase agreement for year 1, cannot sustain financial losses in year 1 on just the possibility of a full-year RA contract for year 2, and is therefore preparing to retire. The possibility of a few monthly RA contracts in year 1 to meet a load serving entity's monthly RA showing or a few monthly CPM designations to address Significant Events does not offer a sufficient expected revenue steam to change the prospects for resource A's viability.

In this situation, then, once identified, the ISO proposes to provide a CPM designation for up to 12 months of year 1 in order to enable resource A to remain in operation to be available for operation during year 2.

Several features of this proposed new CPM procurement category are clarified below.

The ISO would perform due diligence in assessing resource A's financial circumstances to ensure that the expectation of losses for year 1 and the likelihood of retirement are real. This could include, for example, requiring the resource to submit formal notification to the ISO of intent to terminate its Participating Generator Agreement,[42] and sworn statements by executives of the company attesting to resource A's financial condition. In the context of this financial assessment the ISO would also explore other options with the resource owner, such as mothballing the resource for year 1 and restoring it to operability for year 2, that would be lower cost than keeping it on-line for year 1. If it is more cost-effective, the ISO could agree to pay the resource for the costs of mothballing and returning to operability rather than providing a full-year CPM designation.

[42] Under the ISO tariff Attachment G a PGA resource must provide the ISO at least 90 days notice of its intention to terminate its PGA. See http://www.caiso.com/27c3/27c3ebf04ee80.pdf.

Prior to granting a CPM designation for year 1, or an alternative arrangement such as compensating the resource for mothballing costs, the ISO would provide a report for stakeholder review and comment explaining the drivers for the CPM, both in terms of the ISO's operational need in year 2 and, as far as possible given confidentiality requirements, resource A's financial condition making it non-viable in year 1.

If the ISO does decide to provide a CPM designation to resource A for year 1, then for any month during year 1 that a load serving entity contracts with resource A to meet its monthly RAR the ISO would suspend the CPM payment. Thus, the ISO's report mentioned above, combined with this provision to avoid duplicative payments, would provide the signal and the opportunity for load serving entities to procure resource A bilaterally. Moreover, looking ahead to year 2, the ISO expects that such a CPM designation for year 1 would be a signal to the CPUC's procurement and RA programs that resource A is needed for year 2, so that resource A could be procured under a bilateral contract for year 2 and require no further CPM designation beyond year 1.

In response to the ISO's prior straw proposal some stakeholders asked whether the existing RMR structure would be more appropriate for this situation. The ISO believes that the CPM would generally be a superior mechanism for this purpose because it provides the ISO with more useful capacity than the current version of the *pro forma* RMR contract. The *pro forma* RMR contract generally allows the ISO to issue RMR dispatches only for local reliability or to address non-competitive constraints. In contrast, under a CPM designation resource A would have a must-offer obligation comparable to RA resources and would thereby contribute to more liquid day-ahead and real-time energy markets throughout year 1.

<u>ISO Response Post August 23, 2010 Stakeholder Meeting</u>

Stakeholders were generally opposed to the ISO providing capacity payments to resources that are in danger of shutting down due to insufficient revenue but are needed for reliability. PG&E stated that there are already programs in place at CPUC and ISO, noting General Order 167 and RMR contracts that already provide this service. SCE stated the ISO has not demonstrated that other procurement authorities are insufficient and that implementation and cost allocation would be difficult to achieve. SDG&E argued this procurement type would distort negotiations between suppliers and load serving entities. NCPA stated this procurement authority is beyond the scope of the CPM. The CPUC stated General Order 167, Operating Standards 22-25, accomplish the same goal and the ISO should not risk procuring in excess of the planning reserve margin. The CPUC cited this authority could raise prices in bilateral market with yearly designations and the Long Term Procurement Process will address these issues, including the retirement of once-through-cooling units. (For more information on the ISO's once-through-cooling initiative, please refer to the link provided in the footnote below.[43])

The ISO notes that although CPUC General Order 167, Operating Standards 22-25, would provide a basis for preventing utility owned generation from retiring, the CPUC authority would not apply to non-utility owned generation. Operating Standard 24 states, "*This standard is applicable only to the extent that the regulatory body with relevant ratemaking authority has instituted a mechanism to compensate the GAO (Generation Asset Owner) for readiness services provided*." The ISO maintains this standard applies to resources owned by SCE, PG&E, and SDG&E for which the ratemaking authority is the CPUC. Resources owned by merchant generators such as Mirant, Reliant and NRG are under the ratemaking authority of the FERC and thus the CPUC would be unable to compensate these resources.

[43] http://www.caiso.com/1c58/1c58e7a3257a0.html

The ISO views its proposed procurement authority as being complementary to the CPUC process as it already is envisioned in Operating Standard 24 for CPUC jurisdictional resources. Both the CPUC and the ISO version of this concept are bridging mechanisms designed to ensure reliability by preventing the premature exit of resources needed for reliability. This process would also fit into the Long Term Procurement Proceeding process where the ISO and the CPUC could identify resources in needed locations and determine the most efficient way to continue the service they provide.

The ISO envisions that procurement for a resource at risk of retirement would start with the submission by the resource owner to the ISO of a formal declaration of intent to retire at least 180 days prior to the proposed retirement date, which is 90 days in advance of the deadline for providing actual notice of termination under the Participating Generator Agreement. During this initial 90-day period, the ISO would analyze the resource's financial status, assess the impacts of the resource's retirement and determine whether procurement action is needed for reliability reasons to prevent the resource from retiring. If the ISO determines that the resource is not needed for reliability reasons, the ISO expects that the resource will proceed with retirement and provide the required notice of termination under the Participating Generator Agreement.

If the ISO determines that issuing a CPM designation to the resource is warranted to maintain the availability of the resource for reliability reasons, the ISO would prepare a report explaining its analysis and the rationale for its proposed CPM designation. The ISO would issue a market notice to advise stakeholders of the report/and schedule a stakeholder conference call to discuss its findings and hear views from participants.

Next, the ISO would allow the LSEs an opportunity to cure the deficiency. The ISO would allow a period of 30-45 days once it issues the report during which a load serving entity and the resource owner may come forward with a bilateral contract under which the resource would continue to operate. The ISO would collaborate with the CPUC throughout this process for CPUC jurisdictional entities, as contemplated in CPUC General Order 167. In the event that a resource needed for reliability does not obtain a bilateral power supply contract for its services, the ISO would issue a CPM designation. The ISO notes that it intends to work collaboratively with the CPUC through the Long-Term Procurement Process to identify operational needs and resource needs so that necessary units and capacity are procured such that this type of CPM procurement is not necessary. The ISO does believe that having this type of procurement available, particular when the need could arise mid-year during the RA compliance year when there are limited options to address this situation, is warranted and should be part of the tools at the ISO's disposal. The ISO envisions that the likelihood of using this authority is low, but this circumstance should be covered to ensure reliable operation of the system.

PG&E and the CPUC argue that the ISO can use RMR contracts in lieu of this proposed new procurement authority. The ISO agrees that RMR is an important and necessary backstop mechanism, but it is not currently very flexible and is a distinct second choice compared to CPM. As noted above, the ISO's RMR authority under the tariff, although quite broad, is only partially implemented. The current RMR pro forma contract allows the ISO to issue RMR dispatches for local reliability and to address non-competitive constraints. If the ISO were to use its RMR authority for any broader reliability reason, it would have to undertake revisions to the RMR pro forma contract and modify the tariff through a new stakeholder process. In addition, if the ISO were to enter into an RMR contract with a resource not currently on an RMR contract, the ISO has made a previous commitment to initiate a stakeholder process to consider whether RMR cost allocation should be revised. In addition, although the RMR contract is a "pro forma" contract, the schedules attached to each contract are unique to each RMR unit and the rates and costs are determined in a FERC rate case unless agreed upon. Even when rates and costs are agreed upon, extensive and unique negotiations are required for each RMR owner. Finally, the current RMR contract is a yearly contract and any decision to extend must be made by October 1; if the ISO does not extend the contract, it loses the right to designate the generating unit for a year.

CPM, on the other hand, can potentially be used for any reliability need. In addition, the rate and cost allocation are established in the tariff (while still providing the resource owner the right to file for a higher rate at FERC). CPM could be used to bridge the balance of a year in which the resource is not under an RA contract to ensure that it remains available to be considered in the RA process for future years without committing the ISO to extending an RMR contract. The ISO's strong preference is to offer and rely on CPM and only resort to RMR in circumstances where CPM is rejected.

NRG, Six Cities and TURN support the use of CPM to keep units needed for reliability available. NRG stated the ISO correctly identified the concern that older generating units, including units dependent on once-through-cooling, may likely retire given increased capital expenditures associated with retrofitting or repowering but also added caution that a retirement notice could potentially trigger financial hardship. Six Cites recommended the ISO alert the market in time for load serving entities to cure the deficiency. TURN suggested the ISO fully explain the need and report when it was used.

One suggestion posed by a stakeholder is for the resource owner to ask the ISO whether or not a particular asset is needed for reliability. This inquiry would precede the currently required 90-day PGA termination notice timeline to allow the ISO to determine if the resource is indeed needed for reliability. At this time the ISO is recommending that a resource owner who is contemplating retiring a resource under this scenario file the letter to terminate the Participating Generator Agreement earlier than the 90 day timeframe – perhaps as early as 180 days before the intended retirement date – to give the ISO time to determine whether the unit is needed for reliability and to ascertain the legitimacy of the financial circumstances.

A important aspect of this process is how the ISO will determine whether a particular unit is needed for reliability, including for operational purposes to support renewable integration.[44] The ISO envisions that this determination will be made through an analysis of the results of several analysis tools that the ISO either currently has at its disposal (e.g., the once-through-cooling analysis studies tool) or will have in the future (the studies that would be produced on a regular basis as part of the ISO's efforts to determine the operational needs of the system with high levels of intermittent resources). [45] The ISO would use these studies to assess the need for certain units or a group of units in an area. The analysis and the resultant determination of need would be included in the report that would be developed as part of the process. The report would then be posted and explained to stakeholders through a stakeholder call as described above. As an example, the ISO provides below information on the once-through-cooling screening analysis studies tool that was posted on the ISO website (http://www.caiso.com/1c58/1c58e7a3257a0.html). This discussion is intended to highlight the tool and illustrate its ability to assist in this type of analysis.

[44] Note that the ISO can curtail renewable energy to maintain reliability. The objective of the ISO's renewable integration studies is to identify the operational capabilities needed to integrate as much renewable energy as possible prior to possible curtailment to preserve reliability.

[45] California ISO, *Integration of Renewable Resources – Operational Requirements and Generation Fleet Capability at 20% RPS* (August 31, 2010), available at http://www.caiso.com/2804/2804d036401f0.pdf. This study was conducted at the system level, and did not consider the effect of local reliability requirements on the results.

Once-through-Cooling Analysis Tool

The ISO understands stakeholder concerns regarding this type of procurement authority and how the ISO would determine that a particular unit is needed for reliability. The ISO is currently engaged in the once-through-cooling initiative with the State Water Resources Control Board, the CPUC, the CEC and other state agencies to address reliability concerns arising from implementation of the State Water Resources Control Board's adopted policy. A critical component of this initiative is to coordinate compliance activities and generator implementation plans with the applicable balancing authority. The process used to determine whether or not retiring once-through-cooling units are needed for reliability could also be used to determine if other units at risk of retirement could be needed for reliability.

This first stage of this process is to use a load and resource scenario analysis tool to determine the amount of capacity needed based on transmission, generation, demand response and load growth assumptions. The ISO has found that changes in these assumptions or using high versus low load growth can have a substantive effect on the amount of capacity needed. This screening tool will allow the ISO, state agencies and stakeholders to screen for potential reliability impacts (i.e., RA impacts) to local reliability areas under various load and resource scenarios from Assembly Bill 32 California Clean Energy Future.

The ISO has maintained that the proposed CPM procurement method is first and foremost a mechanism to ensure reliability needs are being met that without identified required capacity, grid reliability could be compromised. As was noted in comments filed by the CPUC, General Order 167, Operating Standards 22-25, reference the CPUC working with the control area operator (the ISO) to determine if a unit is needed by either organization before the generator is allowed to retire. Should the generator(s) be found to be needed, then the CPUC as the ratemaking authority could compensate the resource in order to keep it on line.

As contemplated in this revised draft final proposal, some resources that are not currently under an RA contract may be needed to maintain local or zonal area, or even system need under various load and preferred resource scenarios from Energy Action Plan and Assembly Bill 32 California Clean Energy Future. The ISO, in working with the state energy agencies (CPUC and CEC), the State Water Resources Control Board, and stakeholders, performs reliability assessment in three-phase studies for once-through-cooling evaluation. The first develops a load and resource tool (which was posted on the ISO website in July 2010). The second is an initial power flow study which will include load and resource scenarios that resulted in having deficient resources from the screening analysis done in step 1. The third is the reliability assessment incorporating the generator owners' implementation plans.

Since no one can predict when a resource will retire, repower, or retrofit with accurate schedule, the potential need for the ISO to use this CPM authority is a possible reality. The ISO plans to update studies on a regular basis to advise the State Water Resources Control Board and state energy agencies on the potential feasibility of a compliance schedule for affected once-through-cooling generating units. To offset any unintentional retirements of needed resources to maintain reliability, the ISO needs the authority to keep the units operational, if needed -- once units notify the ISO or other regulatory authorities of their intention to retire, or perhaps do not announce such intentions -- to ensure that their plan of action does not impact applicable NERC/WECC reliability standards.

As shown in Chart 1, the ISO ran a power flow study evaluating the local capacity requirements for each of the local reliability areas that have once-through-cooling plants. This value is included in the load and resource scenario analysis tool as local capacity requirement value for each local reliability area and is assumed to increase by an amount equivalent to annual load growth per year. Additional resources, such as renewable additions, combined heat and power, demand response, etc., based on state's policies are included in the screening tool. To perform the studies, the ISO, or stakeholders, can change assumptions based on updated 1 in 10 peak load, retirement status of units, transmission capacity additions, etc. and the results of that model (in the chart below) would show whether the local reliability areas having surplus or deficiencies in resources to serve load.

This is only an example. In the next phase of the once-through-cooling study process the ISO will be conducting a more thorough reliability analysis, which would identify changes in reliability impacts at a more granular level.

Similar to how the ISO conducts an analysis of local capacity requirements for the CPUC to adopt into LSE procurement, the ISO envisions conducting these studies on annual basis to determine if a unit that intends to retire would have a near term reliability impact. The ISO would then work with the CPUC and other applicable state agencies to determine the term of the ISO designation.

Chart 1

	Study Result	Scenario Chosen	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	2	3	5	6	7	8	9	10	11	12	13	14
Big Creek-Ventura	1 in 10 Peak Load (latest IEPR, split to Area)		4,613	4,680	4,749	4,806	4,866	4,928	4,993	5,055	5,118	5,186
	Transmission improvements that affect LCR	12	0	0	0	0	0	0	0	0	0	0
	LCR	0	2786	2852	2922	2979	3039	3101	3166	3228	3291	3359
	Total Net Qualifying Capacity in area as of 2010 plus new additions from scenarios (including supply side CHP additions)	4	5101	5107	5114	5121	5131	5142	5153	5163	5174	5185
	Renewable Construction Scenarios with Potential New Renewable Resource Additions	33% Trajectory Case	0	0	0	0	0	506	506	506	506	506
	Incremental Preferred Demand Side Management	Low Net Load	20	30	96	159	237	331	423	522	618	712
	Demand Response Resources	Low Net Load	225	228	232	235	239	242	246	249	252	256
	Retirements	12	0	0	0	0	0	0	0	0	0	0
	Surplus or deficiency		2560	2513	2520	2536	2568	3120	3162	3212	3259	3300

7.2.6. Compensation for CPM Capacity

In the straw proposal, the ISO proposed two options for compensation of CPM capacity, both using administrative (rather than market-based) pricing but one based on cost of new entry (which was labeled Option A) and the other based on going-forward fixed costs (labeled Option B). The ISO noted that there are pros and cons to both approaches and that either could ultimately be justified as an adjunct to the state's RA program. Both will result in prices that the ISO believes are within the range FERC will consider to be "just and reasonable", but will have different effects on RA contracting decisions. The ISO believes that neither option -- if implemented in isolation from other aspects of the RA program and CPUC long-term procurement planning -- is a well-designed vehicle for eliciting new investment, which in the current market environment, including consideration of substantial renewable energy potentially coming on line over the next decade, would require further guarantees of revenues over multiple years. A more detailed description of the two pricing options is provided in the Issues Paper, and will not be repeated here.

Suppliers have generally argued that CPM prices based on cost of new entry could send the signal that investment is needed in generation capacity and also inform RA contracts for existing resources.[46] In particular, the Western Power Trading Forum argues that without a centralized capacity mechanism, the backstop price becomes the only transparent capacity price for benchmarking forward bilateral RA contracts.

In contrast, a number of other stakeholders were supportive of the continuation of backstop pricing based on going forward costs.[47] They cited the infrequent use of backstop capacity, that the 30 day compensation period will not incent generation and the CPUC has already addressed procurement and reliability planning in the LTPP process. The CPUC and SCE both supported the CEC study used to determine the proposed CPM tariff rate. However, the CPUC cautioned that the $55/kW-year rate could raise prices if applied on an annual basis. TURN suggested a gradual increase to the new proposed rate whereas Six Cities argued the rate should not be based on a new high priced entrant but rather an existing resource more likely to be procured.

In considering the options, the ISO has determined to propose a continuation of backstop capacity pricing based on going-forward fixed costs. This pricing approach has a design basis consistent with procurement from existing generation resources. Given the regulatory design in California, the ISO maintains that investment decisions would have to be largely based on long-term bilateral contracts, as informed by the RA program and CPUC's LTPP, and augmented by the wholesale prices in the ISO's energy and ancillary service markets, along with any modifications to those products and pricing to support renewable integration.

The ISO recognizes that this approach will not provide locational transparency of capacity prices, and that barriers to merchant investment in generation capacity still need to be overcome. At the same time, in the absence of a more complete capacity market design, introduction of backstop capacity pricing based on cost of new entry at this time is not likely to have the desired impact on investment. In the context of this initiative and other related ones by the ISO and other entities, such as the CPUC's long-term procurement planning, the ISO will be providing additional information about future system conditions and the potential needs for new investment. As these needs are clarified in coming years, the ISO retains the ability to revisit how backstop capacity pricing, along with other wholesale capacity reserve products that may be introduced to support renewable integration, could be revised to support needed investment decisions.

The ISO believes that FERC has recognized that backstop capacity procurement is a weak mechanism for supporting investment. In the FERC ICPM Order issued on October 16, 2008, FERC noted that "First, like the pre-MRTU backstop capacity mechanisms (i.e., RCST and TCPM), the ICPM is a mechanism for procuring capacity for short periods to meet system reliability needs and, therefore, is not designed to encourage new investment. Rather, the pricing structure is designed to ensure just and reasonable treatment of non-resource adequacy

[46] In general, merchant generation owners, including Dynegy, Calpine, JP Morgan and RRI, supported pricing at cost of new entry (CONE) net of peak energy rents. Their comments focused on the role of CONE in providing incentives for investment in new capacity.
[47] SDG&E, SCE, PG&E, CPUC, NCPA, TURN, CDWR & Six Cities.

resources that are needed for reliability services and to provide an incentive to these resources to voluntarily accept ICPM designations."[48]

The remainder of this section examines the criteria for the ISO's proposal and provides further details on the basis for determining the proposed rules for calculating going-forward fixed costs.

Design Criteria

The ISO conducted its evaluation of the two options with consideration of the following criteria:

- Improve definition of the backstop capacity product (including duration);
- Provide the correct incentives for suppliers to make units available for backstop capacity designation;
- Provide transparent procurement prices;
- Ensure that pricing rules for CPM support efficient forward (bilateral) markets for RA, with due consideration of stakeholder views, and are "just and reasonable";
- Minimize reliance on backstop procurement where possible by allowing LSEs to procure capacity through bilateral transactions;
- Mitigate local market power when procuring backstop capacity (if needed);
- Minimize administrative costs and implementation issues (i.e., ease of integration into ISO software and market systems).

As a further starting point for consideration of appropriate pricing, the ISO has assumed that in any design for the CPM, the ISO will not (at this time) be providing multi-year contracts for backstop capacity and will not attempt generally to construct a type of proxy centralized capacity market.

More recently, the ISO has been evaluating both capacity needs and operational requirements in the context of renewable integration at 20 percent to 33 percent RPS. Those considerations will increasingly be factored into long-term investment decisions, but need further definition before they can be considered in the design of backstop capacity pricing.

Evaluation of Proposed Pricing Rule

This section evaluates the proposed pricing rule by the criteria noted above, beginning with the more significant criteria.

The principle of pricing based on going-forward fixed costs is that a resource is compensated for its capacity by covering all the costs needed to maintain the resource in operation, although not to provide a return on investment. The pricing rule proposed by the ISO also does not seek refund of peak energy revenues, thus allows for any recovery of revenues over and above going-forward fixed costs, but not below, for the period backstop capacity procurement. As discussed further below, the ISO's pricing rule also sets the going-forward costs at the cost of an expensive resource; among other considerations, this reflects the fact that backstop procurement by the ISO is in effect from higher in the supply stack of existing eligible RA capacity than the RA contracts cleared in the bilateral market.

The ISO believes that for the limited circumstances of CPM designations going-forward costs will be appropriate for the vast majority of eligible resources, and where it is not sufficiently compensatory the resource owner can file resource-specific cost justification with FERC. The voluntary nature of the CPM designation will permit a resource to decline a designation if it believes that its opportunity costs through other means are greater than the CPM price combined with full retention of energy and ancillary service market revenues.

[48] 125 FERC ¶ 61,053 P 41

As noted, prior FERC direction to the ISO on backstop compensation supports the just and reasonableness of the going-forward fixed cost methodology. In the October 16, 2008 ICPM Order, FERC stated, "…the ICPM is a mechanism for procuring capacity for short periods to meet system reliability needs and, therefore, is not designed to encourage new investment."[49] FERC also noted in that ICPM payment based on going-forward fixed costs "… is not unreasonable and provides non-resource adequacy resources with a payment for capacity services that is comparable to the payment received by resource adequacy resources."[50]

Moreover, no stakeholder has argued that without a CPM based on cost of new entry, no further merchant generation investment would take place in the ISO footprint. Moreover, the ISO cannot at this time establish the full multi-year capacity procurement design that would ideally be used to support investment. In the absence of a well designed investment mechanism, a CPM based on cost of new entry could in some locations simply raise capacity prices to buyers without encouraging new entry, and be judged not just and reasonable unless other protective mechanisms were established in the presence of barriers to investment.

The ISO believes that maintaining the going forward fixed cost pricing approach is also consistent with the criteria to minimize procurement through the backstop mechanism. In general, the CPM mechanism is likely to have very limited actual procurement. As shown in Table 1 of this proposal, since the ICPM was approved there has been limited procurement of non-RA resources and corresponding backstop capacity payments.

Although not specifically related to the pricing discussed here, the ISO is now proposing additional selection criteria and a new category of CPM procurement. These changes are intended only to ensure that the ISO has sufficient flexibility to use CPM in the most effective manner when the need arises and should not be interpreted to reflect an expectation that the use of CPM will increase. In fact, the ISO fully expects the use of CPM to be no more frequent than the use of ICPM has been up to now. The ISO is also mindful of the comments that suggest likely impact of the backstop capacity price on the cost of RA capacity procured through bilateral RA contracts.

Moreover, the ISO continues to work with the CPUC to refine various aspects of the RA program, and, importantly, to provide assessments of capacity needs to guide bilateral procurement by load serving entities. The ISO is also committed to providing market information to help anticipate the relative importance of different types of market product revenues in scenarios of higher renewable production.[51]

Other Considerations

The two options were not distinguished on the basis of the other decision criteria noted above:

- Both options shared the same definition of backstop capacity, hence both options are consistent with the criteria to provide a clear definition of the product;
- Both options address any market power concerns associated with backstop capacity pricing.
- Both options can be successfully introduced into ISO market systems by April 1, 2011.

Additional Details and Support for Pricing based on Going Forward Fixed Costs

[49] 125 FERC ¶ 61,053 at P41.
[50] *supra, n.12.*
[51] See, e.g., California ISO, *Integration of Renewable Resources – Operational Requirements and Generation Fleet Capability at 20% RPS* (August 31, 2010).

The ISO's proposal to compensate suppliers for CPM designations on the basis of going-forward fixed costs is essentially the same rule that was adopted for the ICPM and approved by FERC.

The pricing rule would compensate resources at the higher of the tariff rate or a resource's actual going-forward costs plus a 10 percent adder (which must be supported in a cost justification filing with the Commission), without any peak energy rent deductions, *i.e.,* resources will be able to keep all of the revenues they earn in energy and ancillary service markets. Going-forward costs are defined for purposes of this proposal as the sum of fixed operations and maintenance, *ad valorem* costs, and insurance. Going forward costs are generally understood as the minimum fixed costs needed to keep a generator available for operation. As before, the 10% adder is intended to account for any measurement error in the CEC study (described below), hard to quantify costs, or additional costs. In addition, the minimum price as established in the CEC levelized cost report will serve as a further incentive for load serving entities to meet their RA requirements and not rely on the ISO backstop.

The proposed tariff rate, which provides the minimum backstop capacity price, is derived from the going forward fixed costs, plus 10%, of a new 50 MW simple cycle combustion turbine. As indicated above, the CEC studied three types of new combined cycle units and three types of new simple cycle units, which are the most common units being built in California. The small simple cycle unit (constructed by a merchant generator) had the highest going forward costs of all these units. For these reasons, the ISO based its ICPM capacity price on the going-forward costs of the simple cycle unit. The ISO proposes to do the same thing for the CPM.

The ISO again proposes to base the CPM capacity price on the small simple cycle gas unit (as previously used under ICPM), evaluated by the CEC in 2007-2009. To reach a minimum capacity payment of approximately $55/kW-year, the ISO incorporated a 10 percent adder[52] to the going-forward costs of the small simple cycle unit, i.e., approximately $50/kW-year. To the extent that a resource owner believes that its going-forward costs, plus 10%, exceed $55/kW-year it may make a cost justification filing with FERC to obtain a higher capacity payment.

There are several reasons why the ISO again proposes the highest cost unit as the basis for the minimum payment. First, this cost level should cover the going-forward costs of the vast majority of eligible resources, thereby limiting the number of resource-specific cost justification filings that will have to be made with FERC. Second, it will also provide most existing resources that have lower going-forward costs with some contribution toward recovery of their capital costs and return. Third, using this cost level rather than a lower one will be a further incentive for load serving entities to enter into bilateral contracts and not rely on backstop capacity procurement by the ISO. Finally, the voluntary nature of the CPM designation will permit a resource to decline designation if it believes that its opportunity costs through other means are greater than the CPM price along with retention of energy and ancillary service market revenues.

[52] The 10 percent adder is in-line with adders that the Commission has approved in the past. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange,* 96 FERC ¶61,120 at 61,519 (2001); *Public Service Co. of New Mexico*, 95 FERC ¶ 61,481 at 62,714 (2001); *Niagara Mohawk Power Corporation,* 86 FERC ¶ 61,009 at 61,025 (1999); *Terra Comfort Corporation, et al.* 52 FERC ¶ 61,241 at 61,841 (1990). The 10% adder can account for other potential going-forward costs, costs that are difficult to quantify, or a margin for error in the CEC's study. The adder will also serve as a further incentive for load serving entities to enter into contracts to meet their RA requirements and not rely on backstop capacity procurement by the ISO.

The going-forward fixed costs methodology results in a price of $55/kW-year starting April 1, 2011. The ISO proposes that the price would be updated – increased or decreased – each year based on the latest study of going-forward fixed costs. The ISO proposes that the price of $55/kW would be in effect for the period April 1, 2011 through December 31, 2012. The price would then be updated for the period January 1, 2013 through December 31, 2014, and subsequently updated every two years to be effective on a calendar year basis. The applicable rate would be included in the ISO tariff in Appendix F, Rate Schedules, Schedule 6, ICPM Schedules, Monthly ICPM Capacity Payment, and updated every two years**.**

As is the case for the ICPM, the price for the CPM would be based on the CEC's "Comparative Costs of California Central Station Electricity Generation Technologies" study conducted every two years as part of the Integrated Energy Policy Report ("IEPR"). The ISO has contacted the CEC and requested that the report continue to be done every two years due to its importance in establishing the CPM price every two years. If the CEC report is not available for some reason in the future, the ISO would contract for a similar study and report to be conducted by an independent third party.

The current ICPM price was established using the 2007 CEC "Comparative Costs of California Central Station Electricity Generation Technologies" report. In that report, the information used to establish the estimate of going forward fixed costs was in Table E1 – E3, provided below.

CEC 2007 Table E-1 through E-3[53]		**$/kW-Yr (Nominal 2007$)**					
Builder	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Merchant	50	145.3	9.25	7.25	20.36	41.85	**224.01**
IOU	50	112.91	7.3	4.1	20.78	19.47	**164.55**
POU	50	64.98	5.45	6.04	21.27	0	**97.74**

The components of the going-forward fixed costs in the 2007 CEC report that were used to establish the ICPM price, were based on the merchant facility costs highlighted in the table above. These are:

Component	$/kW-year
Insurance	9.25
Ad valorem	7.25
O&M:	20.36
Subtotal	36.86
10% Adder	3.69
Total	$40.55

Rounded to $41/kW-year

53 http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF Page E-1

The CEC issued an updated "Comparative Costs of California Central Station Electricity Generation Technologies" study in 2009. This report was used in the 2009 Integrated Energy Policy Report ("IEPR") that is adopted by the CEC on December 16, 2009.[54] The 2009 report includes Tables B4 – B6 that provide the updated information to that used in the ICPM determination of going forward fixed costs. That table is provided below.

CEC 2009 Table B-4 through B-6[55]		**$/kW-Yr (Nominal 2009$)**					
Builder	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Total Fixed Cost**
Merchant	49.9	198.11	9.63	13.09	27.45	55.13	**303.42**
IOU	49.9	152.53	5.54	10.14	27.88	28.09	**224.18**
POU	49.9	111.14	9.72	9.39	28.4	0	**158.64**

The components of the going-forward fixed costs in the 2009 CEC report, that would be used to establish the CPM price, based on a merchant facility, are:

Component	$/kW-year
Insurance	9.63
ad valorem	13.09
O&M:	27.45
Subtotal	50.17
10% Adder	5.02
Total	$55.19

Rounded to $55/kW-year

The definitions of Insurance, Ad valorem and Fixed O&M as referenced in the 2009 CEC report are as follows[56]:

Insurance Cost - Insurance is the cost of insuring the power plant, similar to insuring a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the life of the power plant. The first-year cost is estimated as a percentage of the installed cost per kilowatt for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.

Ad Valorem - Ad valorem costs are annual property tax payments paid as a percentage of the assessed value and are usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for power plants are set by the State Board

[54] http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

[55] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF Page B5-B7

[56] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF Page 15-16

of Equalization as a percentage of book value for an IOU and as depreciation-factored value for a merchant facility

<u>Fixed Operating and Maintenance</u> - Fixed operating and maintenance (O&M) costs are the costs that occur regardless of how much the plant operates. These costs are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Several stakeholders expressed concern about the increase in the going-forward costs value for ICPM established using the values in the 2007 CEC report ($41/kW-year) compared to the values that result from using the values in the 2009 CEC report ($55/kW-year) - an increase of 34% from the 2007 CEC report. During the August 23, 2010 stakeholder meeting, the CEC presented slides detailing the calculation of going-forward costs.[57] It was noted during the presentation that part of the reason for the large increase in going-forward costs was due to escalating prices in the capital costs for new gas fired generation resources. Additionally, the CEC noted these increases were not adequately captured in the 2007 going-forward price and thus some carryover occurred. The CEC explained that certain costs in the CEC 2009 report, such as operation and maintenance costs, were derived based on actual costs for such elements as reported to the CEC and the costs were not simply derived as a percentage of capital costs (this applies to operation and maintenance costs, ad valorem costs and insurance costs – i.e., the values in the CEC study were based on actual costs and not percentages). The CEC also included a description of the cost of generation model used to derive the going-forward cost. This model is available on the CEC website and can be used by stakeholders as a reference. Stakeholders were encouraged by the CEC to review the model and offer insight into how this model could be improved.

The increase in capital and financing fixed costs and going forward fixed costs in the CEC report from 2007 to 2009 was noted by the CEC in the 2009 report in several sections.[58] As noted above, the higher capital and financing costs appear in part to lead to higher tax and insurance costs, as well as other factors. The increase in fixed operating and maintenance costs are more likely a function of other factors. In short, the higher going forward fixed costs for the unit under consideration appear to be justified.

The ISO recognizes that the use of the going-forward fixed costs of a new 50 MW simple cycle combustion turbine is simply a reference price, and is not connected to investment in any particular generation type. However, the ISO assumes that at least some of the increases in insurance, ad valorem costs, and fixed O&M is characteristic not only of new units but also of existing units. Hence, the ISO will retain the approach of using the new peaker as the pricing reference. The alternative would be to adopt a survey of existing units to find one with a reasonably high priced going forward cost, which based on the ISO's knowledge of RMR costs, would likely result in a similar, and perhaps more arbitrary, pricing result.

Finally, the ISO proposes that when the provisions of this draft final proposal initially take effect, the payment for all CPM designations will be based solely on the compensation rule proposed here. The ISO recognizes, however, that it will be important in the future to revisit the issue of compensation for resources selected for their specific operational characteristics. In parallel to the present initiative the ISO has started a stakeholder process to consider the potential need for changes to market rules, market product and service specifications, and mechanisms for

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[57] http://www.caiso.com/27f8/27f869b73e220.pdf

[58] http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF Pages A-10, 39, 42

procuring specific products and services in the context of integration of larger quantities of variable energy resources into grid operation.[59] For purposes of the CPM design, the ISO believes that any more refined payment structure than what is proposed here should be developed in a manner consistent with this other initiative. The ISO therefore proposes to file the CPM design with a single payment structure for all types of CPM procurement to take effect on April 1, 2011, and then to consider modifying the CPM payment for resource types having needed operational characteristics in conjunction with the renewable integration initiative, where procurement of and compensation for specific resource types will be an explicit topic.

7.2.7. Carryover of Existing ICPM designations on April 1, 2011

If the ISO has previously made an ICPM designation for 2011 as the result of a collective deficiency or a deficiency in an year-ahead RA showing, the ISO retains the right to continue the designation as a CPM designation effective April 1, 2010, but not beyond December 31, 2011, without issuing a new CPM designation. The ISO would issue a market notice indicating that it is extending the ICPM designation as a CPM designation. If the ISO extends the designation of such a resource as a CPM resource, the ISO will pay the resource the CPM price effective April 1, 2010.

7.3. Exceptional Dispatch

This section discusses the following two topics: (1) the proposal for compensation of Exceptional Dispatches that trigger a capacity payment or supplemental revenues depending on the resource's election, and (2) the bid mitigation that would be used for certain types of Exceptional Dispatches.

It is important to note that the March 31, 2011 sunset date established by FERC relative to Exceptional Dispatch applies only to the Exceptional Dispatch pricing and bid mitigation tariff provisions. The ISO's authority to issue Exceptional Dispatches in accordance with Section 34.9 of the ISO tariff does not expire and therefore is not an issue in this initiative.

The ISO proposes to extend all of the Exceptional Dispatch tariff provisions contained in sections 43.15, 34.9.1 – 34.9.3 of the ISO tariff, including the choice to elect either capacity compensation or the supplemental revenues payment option.[60] The ISO proposes one change to Exceptional Dispatch in this proposal, which is price paid to suppliers. This change is discussed in section 8.2.1 below.

7.3.1. Compensation for Exceptional Dispatch Capacity

As stated in the issue paper for this initiative, the ISO has implemented many new operational procedures and software solutions to reduce the number of Exceptional Dispatches. However, as the ISO has consistently reported to stakeholders and FERC, there is a continuing need for the Exceptional Dispatch capability to reliably operate the grid. Therefore, it is important for the pricing mechanism for Exceptional Dispatch to compensate resources fairly for the service they provide.

[59] More detail on the ISO's market and system operations and renewable integration can be found in the ISO's comments to FERC in its recent notice of inquiry on variable energy resources, available here: http://www.caiso.com/2777/2777ac8636f20.pdf. In addition, the ISO will be undertaking a detailed review of market design changes needed to facilitate renewable integration, with documents and schedules provided here: http://www.caiso.com/27be/27beb7931d800.html.

[60] The Exceptional Dispatch provisions are contained in sections 43.15, 34.9.1 – 34.9.3 of the ISO tariff and can be found at http://www.caiso.com/27c3/27c3ea753b1f0.html.

FERC noted in the February 20, 2009 Section 206 Order,

> "The Commission accepts the CAISO's compensation proposal because it provides non-resource adequacy resources with an opportunity to recover the fixed costs associated with any capacity-type services procured by the CAISO through Exceptional Dispatch. During the first 24 months of MRTU, non-resource adequacy resources will have a month-to-month choice between accepting an ICPM designation and earning hourly, bid-based compensation pursuant to the existing Exceptional Dispatch compensation provisions in the MRTU Tariff. Non-resource adequacy resources that choose the hourly, bid-based option and are subject to Exceptional Dispatch mitigation will earn supplemental revenues up to the level of the ICPM payment. We find that both compensation methods yield a just and reasonable result because both methods compensate non-resource adequacy resources in manner comparable to the compensation of resource adequacy resources for providing similar reliability services. The Commission notes that both the ICPM designation offer and supplemental revenues proposal will be available for all Exceptional Dispatch instructions for capacity services for the first four months of MRTU operation. Following the four-month transition period, the ICPM designation offer will continue to be available for all Exceptional Dispatch instructions for capacity; the supplemental revenue proposal will only be available for exceptional dispatches in circumstances where the CAISO has shown there is the potential to exercise market power, i.e., involving non-competitive constraints or the Delta Dispatch. All other non-resource adequacy resources that are exceptionally dispatched will have the option of choosing between accepting an ICPM designation offer and collecting unmitigated Exceptional Dispatch revenues."[61]

FERC also states in this Order, "In sum, we find that by offering an ICPM designation to un-contracted resources that are exceptionally dispatched and providing capacity-type services, the CAISO ensures equitable treatment of all resources providing capacity services in its markets."[62]

The ISO proposes to continue compensating resources for Exceptional Dispatch in a manner consistent with the proposal above for compensating for capacity procured under the CPM.

7.3.2. Bid Mitigation

The ISO proposes to continue the same mitigation provisions that exist today for Exceptionally Dispatched bids. Like today, the mitigation will apply in the limited set of circumstances where there is the potential for exercise of locational market power as currently specified under the tariff.

Bids are currently only mitigated in the following two circumstances:

- **Dispatches to Mitigate Congestion on Non-Competitive Paths.** A non-competitive transmission path is defined as a path for which one or more market participants have the ability to exercise market power. As such, market participants clearly have the potential to exercise market power in the case of Exceptional Dispatches to relieve congestion on non-competitive transmission paths and mitigation is appropriate.
- **Dispatches Made Under "Delta-Dispatch**." Similarly, because only certain resources can be dispatched under the delta dispatch procedures, supply under this circumstance is not competitive and it is appropriate to continue to mitigate bids dispatched under Exceptional Dispatch under the delta dispatch procedures.

As discussed in section 6.2 of this proposal, the amount of Exceptional Dispatches that have been subject to bid mitigation has been a relatively low portion of all Exceptional Dispatches. It has also been a low portion of all bid mitigation. The vast amount of energy dispatched through

[61] 126 FERC ¶ 61,150 P 145
[62] *Id. at* P147

Exceptional Dispatch has been for reasons other than to mitigate congestion on non-competitive transmission paths, which is the sole basis for bid mitigation.

The ISO recognizes the possibility that enhancements to local market power mitigation provisions and the competitive path analysis may potentially be appropriate, and given the broader implications for such changes believes that this is more appropriately addressed as part of a separate stakeholder initiative anticipated to begin in October 2010. This initiative is anticipated to address enhancements to local market power mitigation and will also consider potential enhancements to the competitive path analysis. Consequently, the ISO does not plan to include changes to the competitive path analysis methodology as part of the CPM initiative.

8. Next Steps

The ISO will hold a stakeholder conference call on September 22, 2010 from 1:00 p.m. to 3:00 p.m.to review and discuss this revised draft final proposal. Stakeholders are encouraged to submit written comments by September 29, 2010. The ISO will post the written comments that are received from stakeholders to the following web address http://www.caiso.com/27ae/27ae96bd2e00.html. The ISO will present a proposal to the ISO Board of Governors on November 1-2, 2010.