Issue Paper

Updating Interim Capacity Procurement Mechanism, and Exceptional Dispatch Pricing and Bid Mitigation

June 9, 2010

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1. Stakeholder Process

The California ISO ("ISO") is starting this new stakeholder initiative to update tariff provisions associated with the Interim Capacity Procurement Mechanism ("ICPM") and Exceptional Dispatch pricing and bid mitigation. The entire ICPM, and certain Exceptional Dispatch tariff provisions, expire on March 31, 2011. The Federal Energy Regulatory Commission ("FERC") requires that a tariff filing be made 120 days before the sunset date to prevent a lapse of these provisions. The ISO is planning to make a 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.

June 9, 2010	Post Issue paper
June 14	Post agenda and presentation for June 16 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 final draft proposal
Aug 19	Post agenda and presentation for Aug 23 meeting
Aug 23	Hold stakeholder meeting on final draft proposal
Sep 9	Receive stakeholder written comments on final draft proposal
Oct & Nov	Work with stakeholders on tariff language
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)
Apr 1, 2011	Effective date of new tariff provisions

2. Introduction

The ICPM enables 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.

ICPM and Exceptional Dispatch are currently linked mechanisms in that non-RA[1] capacity is eligible for ICPM designation for "supplemental compensation"[2] in the event that they are committed or dispatched through Exceptional Dispatch. Moreover, the bid mitigation for non-RA

[1] "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.

[2] 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.

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

As noted, the ICPM backstop procurement provisions, and the pricing and bid mitigation provisions for Exceptional Dispatch, expire on March 31, 2011. This sunset date, two years from the implementation of the ISO new market design on April 1, 2009, was established by FERC when it approved these provisions. If the ISO believes that it needs to rely on backstop capacity services beyond the ICPM's proposed 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 when the existing ones expire so there is no gap in applicability.[3]

The proposal that results from this stakeholder initiative will be presented at the November 1-2, 2010 ISO Board of Governors meeting as FERC has ordered the ISO to file its successor to the ICPM and Exceptional Dispatch tariffs 120 days before March 31, 2011.[4]

The ISO has conducted extensive stakeholder processes in developing the current ICPM and Exceptional Dispatch tariff provisions. Extensive background information on both ICPM and Exceptional Dispatch can be found at the following ISO stakeholder initiatives web pages, respectively: http://www.caiso.com/1bc5/1bc5db284cc80.html and http://www.caiso.com/1c89/1c89d76950e00.html.

As a starting point, the ISO does not propose a wholesale redesign of the core elements of the ICPM or Exceptional Dispatch tariff provisions 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, as noted, there could be additional considerations needed to augment the current rules.

The scope of this initiative includes the topics listed below:

1. Determining whether to replace the "interim" backstop procurement mechanism with a permanent mechanism, which would be called the Capacity Procurement Mechanism ("CPM").
2. Modifying the procurement criteria that would be used to select from among eligible resources to recognize operational characteristics that are needed for reliability. For example, the current ICPM criteria do not recognize a growing need for renewable integration requirements.
3. Broaden the ICPM procurement authority through creation of a new category that would allow the ISO to procure capacity for up to 12 months in order to make resources

[3] "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.

[4] "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).

available to the ISO with operational characteristics that are needed for reliable operation of the system.

4. Examining the economic and market design justification and formula established for the ICPM price determination and evaluating whether to retain that formula or change it; if the formula is retained, whether to change the current ICPM price.
5. Examining the linkages between ICPM pricing and supplemental compensation for non-RA resources subject to Exceptional Dispatch. In addition, 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.

This paper describes each of the major topics identified above as well as some of the issues that are anticipated to be raised by stakeholders during the stakeholder process. Stakeholders will have opportunities to provide feedback and identify any additional issues during the June 16, 2010 stakeholder call and in their subsequent written comments.

3. Background

The ICPM was conditionally accepted by FERC on October 16, 2008.[5] 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[6]. The ISOs compliance filings were accepted by FERC orders issues on September 2, 2009[7] and May 4, 2010.[8]] FERC directed the ISO to file any extension if the ISO no later than 120 days before the sunset of both Exceptional Dispatch pricing and bid mitigation and ICPM.

When the ICPM tariff was approved by FERC, it was adopted as an interim measure based on the knowledge that the California Public Utilities Commission ("CPUC") was conducting a proceeding to address long-term RA program issues, including the possibility of a capacity market. One of the major reasons that the ICPM was designed as an interim mechanism was to ensure that the design of ICPM not get out ahead of or constrain efforts to develop the long-term RA framework. As a result, the ISO proposed that the ICPM tariff provisions automatically sunset. At the time that the ICPM was approved by the ISO Board of Governors, management reported that the ultimate goal was to design a long-term backstop mechanism under the ISO's new market design that works effectively under and is aligned with and 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 many stakeholders anticipated in their comments at the time these provisions were filed at FERC. Since April 1, 2009 (14 months), there have been only 15 ICPM procurements, for a total of 455 MW, at a total cost of $1.7 million, with no designation lasting longer than 30 days.

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5 125 FERC ¶ 61,053 (2008), docket Nos. ER08-556-000 and ER06-615-020.
6 126 FERC ¶ 61, 150 (2009), docket nos. ER08-1178 and EL08-88.
7 128 FERC ¶ 61,218 (2009).
8 131 FERC ¶ 61,100 (2010).

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 the needed enhancements as noted above.

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. The ISO intends to initiate a separate stakeholder process later this summer to undertake a comprehensive review of renewable integration market needs, including ancillary service products and markets. This initiative will draw on the results of the operational studies currently in progress to consider what services the ISO needs to reliably operate the grid with renewable resources supplying 20-33 percent of the energy on an annual basis, with variable resources comprising the bulk of that energy, and how best to procure such services.[9] However, this and other related initiatives do not reduce the need for the present 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. Second, even if and when new or redesigned ancillary service products or markets are implemented, the ISO will still need to retain backstop capacity procurement and Exceptional Dispatch mechanisms to assure reliable operation under a diverse range of grid conditions. Although the ISO believes that enhancements to ancillary service products and markets should be designed with the intent of reducing the need to rely on such backstop mechanisms, it would not be prudent to completely eliminate them. Therefore, the ISO believes that it has appropriately specified the scope and timeframe for the present initiative.

4. Interim Capacity Procurement Mechanism

4.1. Overview of Existing Interim Capacity Procurement Mechanism

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.

The key elements of ICPM are:[10]

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

[9] 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.

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

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.

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.[11]
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,[12] plus a 10% adder from that number.[13] The ICPM offers a target annual capacity price of $41/kW-year with 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 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.

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11 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).

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

13 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.

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.

ICPM Procurement since April 1, 2009

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 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 June 9, 2010

#	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[14]						
1	4/21 - 5/20 (2009)	Yuba City Energy Center	1	30 days	Dispatch above RMR Contract	$3,417
2	6/20 - 6/30 (2009)	Humbolt	15	30 days	Outage of RA unit	$21,403
3	8/2 - 8/31 (2009)	Mountain View	2	30 days	Outage of RA unit	$3,892
4	8/2 - 8/31 (2009)	Mountain View	2	30 days	Local transmission outage	$3,892
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 Contract	$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
	Totals		**455.1**			**$1,725,794**

14 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.

Capacity Payment Election under Existing ICPM

The 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.

4.2. Issues for Design of New Capacity Procurement Mechanism

The ISO has identified the following issues for discussion in the effort to design a new CPM to replace the existing ICPM. Stakeholders may supplement this list of issues through their oral and written comments on June 16 and 23, 2010, respectively.

1. Extension Period – Should the new CPM mechanism be in effect for a limited period of time, to be revisited again at a later date, or be open-ended with no expiration date? If a limited time period, how should that period be specified (e.g., calendar time, triggering event, etc.)? If a limited time period is preferred, with what mechanism if any should the ISO replace the CPM when it expires? The ISO believes that given the conclusions of the CPUC long-term RA proceeding, it is preferable to establish a permanent mechanism at this time, based on market design principles.

2. Compensation to be Paid for Capacity – There are two parts to this question. First, what costs should the capacity payment be designed to recover? Second, based on the answer to the first question, how should the ISO determine the compensation rate empirically?[15]

Compensation has been one of the more complicated and controversial issues with backstop procurement, largely because of the first fundamental design question noted above, *i.e.*, whether such compensation is intended to provide incentives for new investment or to buy available non-RA capacity from existing plants. In future years, pricing may become even more complicated, as the ISO will also be faced with the need to ensure that specific operating capabilities are available from the installed capacity due to the simultaneous policies of a 33% Renewable Portfolio Standard by 2020 and banning of plants with once-though cooling by 2021.

[15] "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." *See FERC* Order on Section 206 Investigation, 126 FERC ¶ 61,150 at P248

These changes to the generation mix may also change the value of capacity in ways not anticipated by current RA and backstop procurement rules.

To date, pricing for backstop capacity has been evaluated three times, concluding with the ICPM. The first explicit backstop capacity mechanism, the Reliability Capacity Services Tariff, was established in 2006 to complement the then existing FERC Must-Offer Obligation for all generation capacity. Its Target Annual Capacity Price was set at $73/kW-year, subject to *ex-post* deductions for peak energy rents and other adjustments. While this was a negotiated value that was included in an Offer of Settlement, FERC approved it as a just and reasonable rate in the context of a FERC-imposed Must-Offer Obligation. The Reliability Capacity Services Tariff price was then increased by 6.7 percent in 2008 under the Transitional Capacity Procurement Mechanism. Concurrently, the ISO worked to establish the rules for a backstop mechanism consistent with the rules of the redesigned ISO wholesale markets and the expiration of the FERC Must-Offer Obligation.

Between 2005 and 2008, the cost of new generation increased sharply, as reflected in a 2007 CEC study that estimated the cost of new peakers at $150-$200/kW-year. This cost increase made further inflation-based increments of the 2007-2008 Reliability Capacity Services Tariff/Transitional Capacity Procurement Mechanism price implausible *if* the purpose of backstop capacity procurement was in part to signal new investment. Over 2007-2008, the ISO presented several papers exploring both:

- Alternative market-based and tariff-based methods for establishing a backstop price, albeit “interim”, that could be referenced to cost of new entry and capacity conditions in particular locations; and
- Tariff-based methods for establishing a backstop price that was intended to cover the going forward costs of existing generation.

Stakeholders were largely split among these options, depending on whether they were buyers or sellers.[16] In evaluating these options, one consideration at the time was the ongoing CPUC proceeding examining a multi-year forward RA requirement and a centralized capacity market. Some stakeholders believed that conducting a separate process to establish an interim backstop mechanism explicitly designed around new entry would interfere with the development of the CPUC proceeding. In addition, some stakeholders, including the CPUC, were concerned that an ISO backstop price based on cost of new entry would supplant the bilateral RA price, at least in some locations, resulting in cost of new entry payments to existing generation without consideration of whether new generation was or could be sited at those locations. More generally, there was the design consideration that an interim, short-term capacity mechanism, with procurement typically for a monthly period, was not a basis for new entry regardless of what price it would set.

In its review of the options, the ISO ultimately concluded that options in either category would provide a just and reasonable price (i.e., none would confiscate non-RA capacity) depending on the purpose of the backstop mechanism in the context of the RA program. If the purpose of the mechanism when it covered RA deficiencies (as opposed to significant events) was to complement the existing RA program and provide transparent prices that reflected scarcity of capacity, then cost of new entry could be a reference point in the pricing model, especially in locations where capacity was tight as measured by the results of annual or multi-year Local

[16] Merchant suppliers generally supported a price based on the cost of new entry – and some supported that price for all backstop procurement -- whereas LSEs, the CPUC and the California Electricity Oversight Board generally supported lower prices (many supporting either cost-based prices similar to the structure of RMR Agreements, or a going-forward fixed cost methodology on a per unit basis).

Capacity Requirements studies. However, the ISO did not support a cost of new entry price as a uniform price (in all locations and at all times, e.g., to cover significant events), because locations where capacity was in substantial surplus did not justify a cost of new entry-based price. Rather, at a minimum, the pricing mechanism needed to reflect capacity surplus by providing for locational capacity prices that were proportionately less than the cost of new entry. As such, the approach set forth by the ISO, based on capacity market design principles deployed in other markets, would have calculated a market-proxy price derived from an administrative capacity demand curve and a price floor for areas in surplus. It would have included a peak energy rents deduction, possibly by location. The demand curve for backstop procurement for the RA programs was capped at an estimate of the cost of new entry in areas at or slightly below their RA requirements. Under this approach, the cost of new entry price applied initially to four local areas (out of 10 local areas).[17]

This design proposal was not adopted, in part because of its potential complexity and also because of strongly voiced concerns that it would supplant the existing RA pricing model (prior to conclusion of the CPUC proceeding) and result in a shift in procurement to the backstop mechanism. Also, the purpose of the ICPM was not to incent new generation; it was to procure existing generation to meet a specific current need, *e.g.,* a significant event or a shortfall in RA procurement.

The other class of pricing options was based not on cost of new entry but rather on the going forward costs of the existing generation procured on a backstop basis. The economic and market design justification for this approach is that the backstop mechanism is not intended to provide entry price signals. Rather, because by definition it is only procuring capacity from existing resources, the price should be based on the going forward costs of capacity; that is, the costs of operation and maintenance, insurance, taxes and other factors that need to be covered for the resources to remain in operation for the period in question.

The pricing rule proposed by the ISO was to set the backstop price of capacity at the going forward cost of an expensive unit, giving suppliers the option also to file at FERC for a higher going forward cost rate. The pricing rule was based on four criteria: (1) to benchmark the price in publicly available information, notably the results of a June 2007 CEC study that identifies the going-forward costs of new generation in California (as a component of the total cost of new generation); (2) consistency with FERC's rationale in the order approving the Reliability Capacity Services Tariff Settlement not to create incentives for buyers or sellers to shift procurement to the backstop mechanism; (3) that the price was sufficiently high to cover the "going-forward" costs of most generators that might be designated under ICPM (thereby reducing the need for individual generator cost justification filings); and (4) not to change the incentives of CPUC-jurisdictional LSEs to procure RA prior to ICPM given the existing CPUC penalties and the $40/kW-year trigger used by the CPUC to consider LSE requests for waivers from procuring capacity to meet RA requirements.

The ISO thus proposed and FERC approved a uniform target annual capacity price of $41/kW-year be paid for all capacity procured under the ICPM regardless of the type of procurement. The $41/kW-year price is based on 2007 CEC cost estimates of the going-forward costs of gas-fired single and combined-cycle generating units. Payment is adjusted by an availability factor that was formerly in the Reliability Capacity Services tariff and a level (1/12) monthly shaping factor (i.e., the Target Annual Capacity Price of $41/kW-year would be divided by 12 to determine the target monthly capacity price). In addition, 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

[17] *See* slide presentation at, http://www.caiso.com/1c75/1c75e06a6b710.pdf. *See* paper at http://www.caiso.com/1c91/1c91b9f063f90.pdf

than $41, but the owner has to justify that price to FERC based on the same types of costs that produced the $41/kW-year default price. Further, suppliers are permitted to retain all market revenues (i.e., no peak energy rents deduction).

The pricing reflected in the ICPM recognized at that time that long-term RA design issues were still being discussed, which made it difficult to design a more permanent market-based pricing rule. When the ISO filed the ICPM at FERC, the ISO stated that it would initiate discussions with stakeholders regarding a permanent market-based pricing mechanism for backstop procurement in connection with implementation of a long-term RA design and seek to ensure that both structures are complementary.

3. New CPM Category to meet Key Operational Needs - The ISO intends to broaden the scope of the CPM somewhat by allowing for procurement up to one year in duration for resources that will be needed for such a period to help assure continued reliable operation. The ISO would utilize this type of procurement in instances where it identifies specific resource needs, based for example on a resource's operating characteristics or location, that may not be captured in the local capacity requirements for RA procurement of local capacity and are not associated with any identifiable potential significant event. The driver of this procurement would be operational need. This category would be distinct from the three existing triggers of ISO backstop capacity procurement: (1) backstopping the RA program, (2) significant event, or (3) triggered by exceptional dispatch. It would be a fourth category of backstop procurement.

4. Modify Criteria for choosing among Eligible *R*esources - For the design of the new CPM the ISO will seek to modify the existing ICPM criteria for choosing which resource will receive the CPM designation when there are multiple resources available and eligible to meet the same need. Specifically, the ISO proposes to include consideration of the operational characteristics of resources as explicit criteria for making such selections, to ensure that the ISO can always select the resource that best meets the identified need. Operational characteristics that would be considered may include minimum operating levels, ramp rate at different levels of production, and ancillary services capability, particularly regulation. For example, if the ISO experiences a local deficiency, and there is substantial variable energy on the system, the ISO may desire to be able to select a dispatchable resource over a non-dispatchable resource, a resource that is not use-limited over a resource that is use-limited, or a resource with ramping capability, or greater ramping capability compared to another resource**.**

5. Treatment of Resources procured under Exceptional Dispatch but then go out on Planned Outage –The ISO would like to resolve a problem with the existing ICPM that arises when a resource receives an Exceptional Dispatch and is paid a 30-day ICPM capacity payment, but then goes off-line for a scheduled outage before the 30-day ICPM period is over. Since outages would usually have been approved prior to the Exceptional Dispatch, under the current rules the ISO could be entering into a 30-day ICPM contract, even though it is known at the time that the resource will not be available for the full 30 days. An example of this occurred under the Transitional Capacity Procurement Mechanism on December 19, 2008, just before the transition to ICPM with the start of the new market structure, when the ISO denied waivers[18] for Ormond Beach 2 for 775 MW, at a cost of $3.5 million. Prior to the waiver denial, the ISO had approved an outage from January 4, 2009 to February 6, 2009. The same type of scenario can occur under the Exceptional Dispatch and ICPM provisions. The ISO believes it is not appropriate to

[18] The Exceptional Dispatch mechanism went into effect with the start of the ISO's new market structure on April 1, 2009. Prior to that time the comparable mechanism was the "must offer waiver" process whereby a resource could request of the ISO a waiver of its FERC-ordered Must Offer Obligation. The ISO's denial of such a waiver request would then trigger a 30-day capacity payment under the Transitional Capacity Procurement Mechanism provisions, which preceded the ICPM.

pay a resource for 30 days of capacity if that resource is not available for the full 30 days; therefore, the ISO believes it is necessary and appropriate in the context of this initiative to adopt rules for the new CPM that resolve this problem. Two options for consideration, which are not mutually exclusive, are (a) to pay the CPM resource the CPM compensation for the minimum of 30-days or the number of days between the Exceptional Dispatch and the start of the scheduled outage, and (b) allow the resource to provide equivalent substitute capacity from another resource for the days when the Exceptional Dispatch resource is out of service. For example, tariff section 43.6.1 could be revised to remove "is not on an authorized Outage" or to read "is not on an authorized Outage that was approved after the ICPM designation." This would encourage the Exceptional Dispatch resource owner to delay the outage until after the 30-day CPM designation period, cancel and request to reschedule the outage, or offer a substitute resource.

5. Exceptional Dispatch

Like ICPM, some of the pricing and settlement rules, including market power mitigation, for Exceptional Dispatch will terminate in March 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 reduce the need for Exceptional Dispatch is outside the scope of this issue paper; 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.

5.1. Overview of Exceptional Dispatch

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.

[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.

Typically, an Exceptional Dispatch is required to address unanticipated conditions as well as transmission constraints or generation unit operating constraints that was not captured in the models used in the Integrated Forward Market, the Reliability Unit Commitment or the Real-Time Market, but is needed for system reliability.[20] A detailed description of practices and rules for Exceptional Dispatches is provided in a *Technical Bulletin.*[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 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 or affect locational marginal prices). If not subject to mitigation, any such Exceptional Dispatch for incremental energy will generally be paid the higher of: (1) resource's energy bid price; (2) resource's default energy bid; or (3) locational marginal price at their location.[22] Bids subject to mitigation will generally be paid the higher of the default energy bid or locational marginal price.

5.1. Mitigation of Bids used for Exceptional Dispatch

The ISO's original design for the new market did not include Exceptional Dispatch bid mitigation provisions. Over 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 resolve a particular constraint, bids dispatched through Exceptional Dispatch should be subject to mitigation in defined conditions. FERC ultimately 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.

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[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.

[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.

As discussed in the next section of this paper, 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.

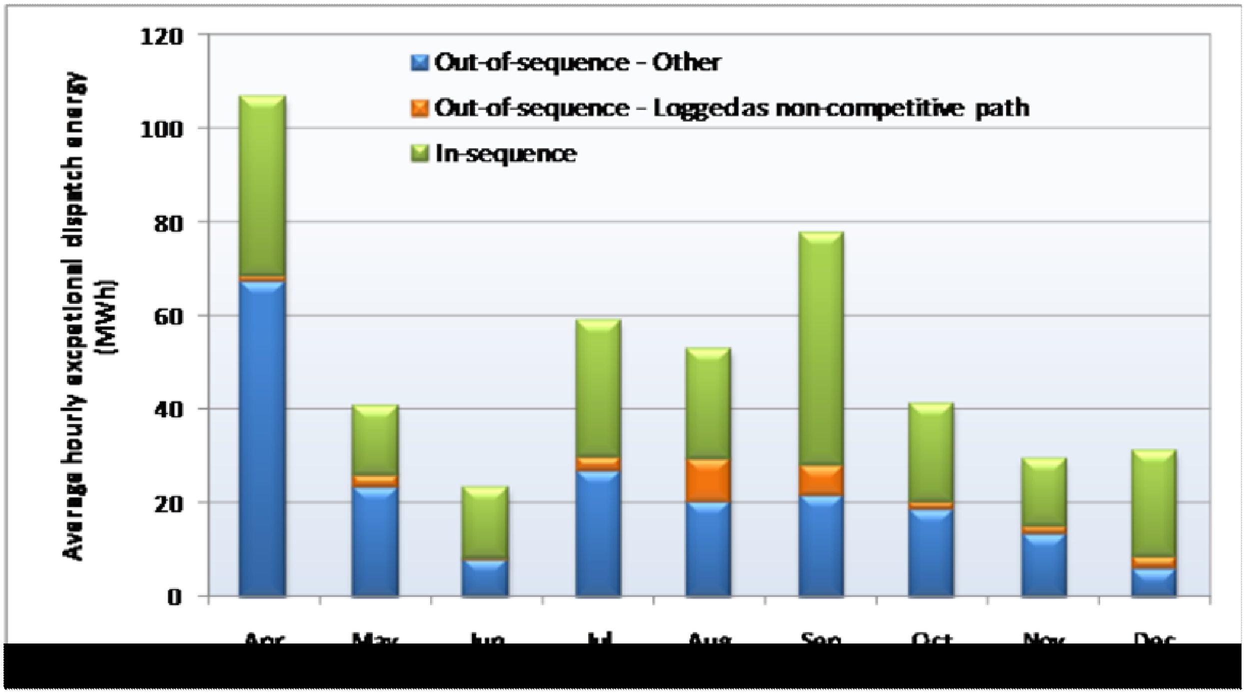
The specific methodology currently used to mitigate bids that are dispatched under Exceptional Dispatch depends on the payment option the market participant has chosen for the resources.[24] If the supplemental revenues option is chosen, then the resource's bid price in individual hours is not mitigated 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; however, 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 have 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.

[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



5.2. Compensation for Non-Resource Adequacy Capacity Dispatched Under Exceptional Dispatch

"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.

5.3. Exceptional Dispatch Bid Mitigation Issues

When the ISO initially proposed rules for mitigating bids dispatched through Exceptional Dispatch to FERC in 2009, it requested authority to mitigate bids dispatched under a variety of circumstances. FERC ultimately approved mitigating bids dispatched through Exceptional Dispatch under the two fairly limited circumstances described in the preceding section (i.e. (1) dispatches to mitigate congestion on non-competitive paths, (2) bids dispatched under "delta dispatch").[29] The ISO concludes that it is appropriate to continue mitigating bids dispatched through the exceptional dispatch process to address market power in the fairly limited set of circumstances currently allowed under the tariff:

- **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.

5.4. Exceptional Dispatch Supplemental Revenue Compensation Pricing Issues

Because of the close linkage between the pricing of supplemental revenues compensation for non-RA resources and the price of backstop capacity procurement, if the supplemental revenues compensation approach is sustained, it will be dependent on the results of the backstop pricing rule that is ultimately adopted.

The ISO continues to believe that for non-RA capacity utilized through Exceptional Dispatch, the incremental backstop capacity procurement method of providing supplemental compensation is the most reasonable method for providing capacity payments. Hence, the ISO proposes to continue this basic linkage between the Exceptional Dispatch supplemental compensation and the backstop capacity rules.

The ISO has not observed many instances of resources opting for the "relaxed mitigation" option rather than the incremental ICPM designations. Hence, for purposes of simplification, the ISO would propose removing that option from the tariff.

6. Next Steps

The ISO will hold a stakeholder conference call on June 16, 2010 from 1:00-4:00 p.m. to discuss the topics presented in this issue paper. Stakeholders are encouraged to submit written comments on the issue paper and the discussion that occurs during the June 16, 2010

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

[29] FERC approved broad application of bid mitigation for the first four months of the new market. Beginning August 1, 2009, bid mitigation applied only to Exceptional Dispatches for non-competitive constraints and for delta dispatch.

conference call to bmcallister@caiso.com by close of business on June 23, 2010. The ISO will post a comments template to the following web page http://www.caiso.com/27ae/27ae96bd2e00.html the day after the June 16, 2010 conference call, and stakeholders should use that template when they submit their written comments. The ISO will post the written comments that it receives at the same web page where the comment template will be posted. The ISO will then review stakeholder comments and consider stakeholder input as it prepares a straw proposal. The straw proposal is scheduled to be posted on July 15, 2010.