California ISO

Draft Final Proposal

Renewable Integration: Market and Product Review

Phase 1

November 4, 2011

Draft Final Proposal
Renewable Integration: Market and Product Review - Phase 1

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1 Executive Summary

The ISO began Phase 1 of the Renewable Integration – Market and Product Review, (RI-MPR) in September, 2010.[1] The purpose of this initiative is to identify short-term solutions for integrating renewable resources onto the grid. The scope of Phase 1 was originally comprised of two market design changes: (1) re-evaluate the Participating Intermittent Resource Program (PIRP) and (2) lower the energy bid floor to provide additional incentives for market participants, including variable energy resources (VER), to submit decremental (DEC) bids enabling the ISO to manage over-generation and congestion more efficiently and transparently. As the stakeholder process and market design effort evolved, bid cost recovery changes were added to the proposal to address identified needs to balance the effects of lowering the bid floor on generation suppliers.

The ISO conducted an extensive stakeholder process to develop of each of these components and finalize this proposal. Stakeholders provided invaluable feedback allowing the ISO to understand how these changes impact each segment of our market and allowed us to craft a proposal that moves the ball forward in facilitating renewable integration and enabling cost allocation based on cost causation.

The specific proposals included herein are:

- Update participating intermittent resource program (PIRP) cost allocation. PIRP will be retained for existing PIRP resources and available to new participants. In most cases uplift costs from PIRP will be allocated to load serving entities that have contracted with PIRP resources. New wind or solar resources that wish to be eligible for PIRP will need to identify the entity that consents to bear the allocation of the PIRP uplifts Once in PIRP, the uplift costs for that particular resource would then be allocated to that entity. Load serving entities with resources currently participating in PIRP will also need to provide the ISO with information so that the allocation of the uplift can be properly recognized in ISO systems.
- Reduce the energy bid floor. The ISO will lower the bid floor from -\$30/MWh to -\$150/MWh in the first year and to -\$300/MWh in the following year. The objective of this rule change is to foster additional dispatch flexibility over time from thermal and renewable resources as well as new storage technologies. In particular, the bid floor is intended to account for the opportunity cost of curtailment faced by wind and solar resources and the scheduling coordinators that bid them into the market. Additional details regarding this element of the proposal are in Section 3.
- Change the bid cost recovery netting methodology. This policy change seeks to modify the ISO's netting methodology for bid cost recovery to ensure costs incurred by resources in one market do not diminish revenues received in another market. The ISO recognizes that, without this change, it could erode the incentives for supply resources to bid flexible resources economically into the real time market, which is counter to the over-arching goal of this initiative.

[1] RI-MPR actually began in July, 2010 with a discussion paper that set the stage for Phase 1 and Phase 2 of the project. RI-MPR Phase 1 identifies short term solutions while Phase 2 considers mid- and longer term solutions. The Phase 2 initiative was kicked off with a scoping paper and stakeholder meeting in April, 2011.

The proposals described in this paper will be discussed at a stakeholder conference call on November 8, 2011. Please submit stakeholder comments by November 18th to RI-MPR@caiso.com.

2 Participating Intermittent Resource Program (PIRP)

2.1 Introduction

The PIRP was designed and implemented well before there was a clear expectation of the enormous growth of variable renewable resources that will occur under higher Renewable Portfolio Standard (RPS) and without the benefit of what we have learned from the studies of the operational impacts of renewable integration. In January of 2002, the ISO filed Tariff Amendment 42 at FERC to introduce provisions to facilitate the participation of eligible intermittent resources into the ISO markets. The following passage from the filing provides the original goal for PIRP:

> *At its July 2001 meeting, the ISO Board of Governors directed ISO Management to work with representatives of the California Wind Energy Association, the American Wind Energy Association, the Independent Energy Producers Association, the California Department of Water Resources, the Governor's office, the investor-owned utilities and other interested parties to develop a consensus proposal for facilitating the participation of intermittent resources in ISO markets. Shared objectives include encouragement of investment in new wind, solar and other environmentally-benign intermittent Energy resources, a need for new rules for the scheduling of intermittent resources that will mitigate the variability of the financial impact of Imbalance Energy costs resulting when such resources inevitably go "off-schedule" (e.g., when wind patterns change), help such projects gain access to debt financing, ensure operational reliability of the ISO Control Area while permitting grid access to such Energy resources and finally, minimize cost shifting to other Market Participants as may transpire through the effort to encourage a greater diversity in California's Energy resource portfolio.* [2]

The ISO's current cost allocation proposal for PIRP continues to align with this vision.

2.2 Background

The ISO's renewable integration studies have shown that the ISO will have an increasing need for dispatchability as more variable energy resources are added to the generation fleet to meet the 33% RPS. The need for dispatchability is not simply relevant to instances in which there were actual shortfalls. In fact, the magnitude and frequency of downward capacity shortfalls identified by the ISO's renewable integration studies were somewhat limited. However, the ISO's 33% RPS study shows that significant system costs can be incurred if downward flexibility must be maintained by loading internal flexible gas resources and reducing more economic imports. As a result, price-responsive curtailment of renewable resources is a more efficient solution to economically meet downward-flexibility requirements which will continue to increase as more variable energy resources are added to the system.

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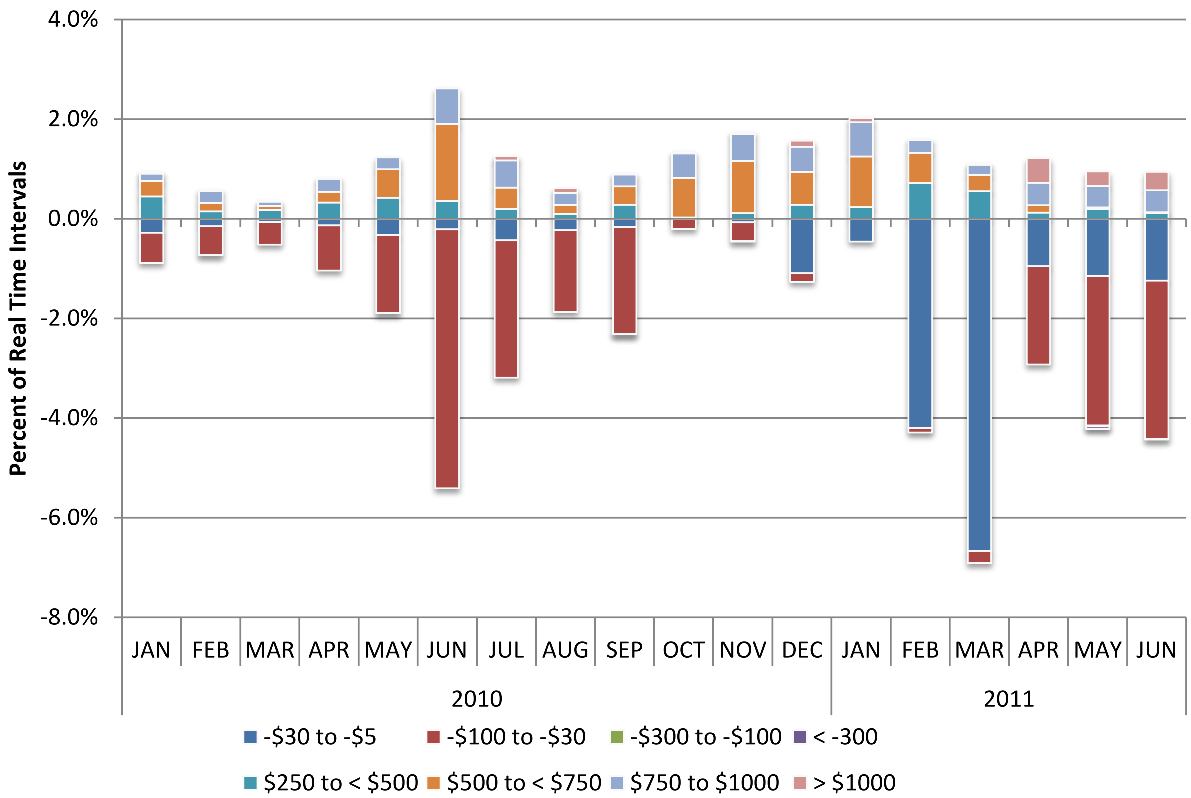
[2] The full text of this filing can be found at: http://www.caiso.com/Documents/Intermittent%20Resources%20FERC%20filing%20in%20Amendment%2042

There are other conditions under which the CAISO needs to be able to economically curtail such resources. These situations are generally seen when grid conditions produce negative prices at the nodes for certain generating resources. Under these conditions – the frequency of which is described in the chart below – it would both be more efficient and enhance grid reliability by economically curtailing generating resources. Having resources submit economic bids and respond to ISO dispatch instructions will lead to more reliable system operation and allow the ISO to efficiently dispatch resources to meet system needs. Economic bids[3] supplied by conventional and variable energy resources will lead to lower renewable integration costs and greater system reliability.

Figure 2.1 – Frequency of Real-Time prices by range – January 2010 to June 2011



Some parties have pointed out that the bilateral power purchase agreements between load-serving entities and renewable resources provide the ability for an LSE buyer to curtail the supplier's renewable resource, and have asked why such provisions are not sufficient to enable the ISO to reduce the amount of energy these resources are injecting into the grid under conditions of system over-generation or local congestion. The reason why such provisions are not sufficient is that they do not provide a mechanism for the ISO to direct the curtailment of the resources in real time in response to an immediate over-generation or congestion condition. To obtain the real-time curtailment response the ISO needs to maintain reliable operation under over-generation or congestion conditions, the ISO must have the ability to issue DEC

[3] Economic bids represent a resource's marginal cost of providing energy.

instructions through its markets directly to the needed resource, with adequate incentives in place for the instructed resource to respond to the DEC instruction.

Given the significant benefits of increased dispatchability from variable energy resources, the ISO is proposing limited near-term changes to the PIRP through this phase 1 of the renewable integration effort. The ISO is proposing enhanced settlement provisions to provide visibility to LSEs on the deviation costs of each PIRP contracted resource. In the longer term, the ISO is considering more comprehensive enhancements to its market design that will better meet the operational challenges of renewable integration and accommodate the technological constraints of variable energy resources.

The ISO is also examining alternatives to accommodate the variable output of PIRP resources in phase 2 of the renewable integration effort. Until that time, this proposal is designed to provide greater transparency on PIRP costs that could incentivize voluntary changes to PIRP participation and thus serve to mitigate PIRP uplift costs. The ISO believes that this provides a reasonable balance for providing a mechanism for VERs to manage their deviation risks as well as provide opportunities for resources to exit the PIRP program. Technological advances in forecasting and manufacturing help to limit renewable resource variability and lessen the need for PIRP going forward. In addition, options such as convergence bidding (that did not exist when PIRP began) provide hedging mechanisms for these resources that can be used to further manage their deviation risk.

2.3 Proposal

There are two proposed changes to the current PIRP program:

1. For existing PIRP resources, uplift costs associated with PIRP will be allocated to LSEs that have PPAs with PIRs instead of net negative uninstructed deviators; new PIRs or PIRs whose contract terminate or expire must identify the Scheduling Coordinator who has agreed to the allocation of these PIRP uplift costs. [4]
2. Pseudo-tie generating units, and dynamic schedules that deliver 100% of the associated generating units output to the ISO, that meet the PIRP eligibility requirements may choose to participate in PIRP as a settlement option that supplements the ISO's dynamic transfer congestion management options.

The following table shows how the cost allocation will be set up for each type of PIRP resource:

Status of resource	Cost allocation
Existing PIR with an PPA (certified as a PIR prior to the date of the FERC order)	The LSE will provide a list of existing PIRs with information so the master file link can be set up for settlement purposes (SCID, MW, term).
New PIR or Existing PIR whose PPA terminated or expired	PIR will (with counterparty's consent) provide information of SC that will be allocated uplift costs so the master file link can be set up for settlement purposes (SCID, MW, term)

[4] The SC who agrees to the allocation of these uplifts could be the SC of the LSE, the SC of the resource or some other party who agrees to take on these costs, perhaps to facilitate a pooling service outside of the ISO settlements.

Other PIRP elements will remain unchanged at this time, although the ISO expect to begin a new initiative early next year to develop a proposal to enhance PIRP to allow resource to participate in PIRP and submit decremental bids. Under PIRP, scheduling coordinators for PIRs must submit an hourly self schedule that aligns with the ISO issued forecast. Deviations from this schedule are netted over the month and then paid out (or charged).

Eligibility requirements

Appendix Q of the tariff provides that when an eligible intermittent resource intends to become a PIR, they must have the following agreements in place: (1) a Participating Generator Agreement (PGA) or QF PGA, (2) a Meter Service Agreement (MSA) and (3) a letter of intent as specified in the Market Operations BPM.[5] Additional requirements include (1) installation of equipment to provide communication and support forecast data, (2) sufficient data to support an unbiased forecast and (3) information requirements for the PIRP export fee. Once all of these requirements are in place, the ISO will notify the scheduling coordinator of the resource and the resource owner that they have been certified to schedule as a PIR.

This proposal adds one additional requirement to the certification process. The resource must provide information regarding the SC of the entity that agrees to bear the cost allocation of the uplifts. Generally speaking this will be the SC of the LSE that contracted with the resource and agreed to its participation in PIRP (see the table above for more details). This information will be used to ensure the proper allocation of the PIRP uplift costs. The following information will be required:

- the PIR;
- the SC;
- the percentage of the total output contracted;
- the expiration date of the contract

All resources will be required to provide this information in order to be certified for PIRP. This data will be used to link the PIR to the SC in the master file for settlements purposes.

Based on the information provided, the ISO will update the master file to create a link between each PIR and the SC. After the end of the month, the netted deviations for each PIR will be allocated to each SC according to the contracted MW or percentage provided in Master File. This functionality does not exist today and will need to be developed.

Dynamic Transfers

In the Dynamic Transfer and the RI-MPR Phase 1 stakeholder processes some parties requested that dynamic intermittent resources have the option to participate in PIRP. On May 19, 2011 the ISO Board of Governors approved the dynamic transfer proposal, with most features being effective November 1, 2012, and certain enhancements having an expected implementation date of spring of 2013. One of the chief outcomes of this proposal is that it revises the dynamic transfer rules to accommodate renewable energy resources[6]. Among the notable parts of the dynamic transfer proposal are:

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[5] See Tariff Appendix Q, Section 2.2 *Minimum Certification Requirements*, for further details - http://www.caiso.com/Documents/AppendicesM-R-FifthReplacementCAISOTariff.pdf .

[6] The Dynamic Transfers Final Proposal is posted at http://www.caiso.com/2b72/2b72e3f642fa0.pdf .

- Effective in spring 2013 dynamic transfers will be able to bid to establish a transmission reservation that is greater than its energy schedule, to ensure that transmission is available for its maximum expected transfer. Within an operating hour, a dynamic transfer may be dispatched above or below its transmission reservation based on available transmission. If a dynamic transfer delivers above its reservation and actual flows on the path exceed the flow limit, the dynamic transfer must comply with operating orders to reduce deliveries to the level of its transmission reservation.
- Within the operating hour, dynamic transfers of intermittent resources will have two scheduling options, as of spring 2013, so that they will be able to update their expected available energy deliveries on a five minute basis. Either they can be dispatched at their current delivery to track the generators' variable output, or dispatched from the resource's own forecast to reflect factors including firming and shaping by external resources. These options recognize that the ISO faces scheduling requirements on interties that do not apply within the ISO, and allow the ISO to maintain intertie schedules within the available transfer capability while also maintaining the highest possible utilization of the intertie capacity. If the ISO's dispatch is less than the intermittent resource's current delivery (as of the start of the real-time dispatch process) or the resource's forecast for the dispatch interval, the resource output is expected to be reduced, even before the ISO issues an operating order. Conversely, if an intermittent resource's current delivery is less than its transmission reservation, recognizing its current delivery as the ISO's dispatch of the intermittent resource allows the ISO to dispatch other dynamic transfers to use the available intertie capacity, if other dynamic transfers use the same intertie.
- Dynamic transfer resources must be able to respond immediately to intertie schedule curtailments.

These processes are founded on knowledge that intermittent resources are delivering up to their full availability (unless they are otherwise instructed by the ISO), separately from variations in the ISO's LMPs, the separation of delivered energy into instructed versus uninstructed energy, or PIRP's settlement of uninstructed energy. PIRP's treatment of an hourly schedule as instructed energy, and an intermittent resource's varying availability between dispatch intervals within an operating hour, do not interfere with the value of establishing dispatch operating targets as the ISO would otherwise do for dynamic transfers of intermittent resources, in terms of managing intertie capacity. Dispatch operating targets can continue to inform resources of the occurrence of congestion (which could become operating orders if not complied with), and to establish realistic real-time schedules that allow the ISO to fully utilize its intertie capacity. Thus, the applicability of PIRP in settlements can be separated from the use of dispatch instructions in management of intertie capacity, and the decision to allow dynamic transfers of intermittent resources can be based solely on its settlement implications.

Another issue is that there are two types of dynamic transfer resources: pseudo-ties and dynamic schedules. Although they are similar in many aspects there can be a key difference that affects how they are considered under the PIRP proposal. All output of a pseudo-tie resource is under the control of the ISO. However, if a resource uses a dynamic schedule, the ISO has real-time dispatch control over only the dynamically scheduled portion of the output, which may not be the entire capacity of the resource. The possibility that the ISO will only see a portion of a resource's total recorded output creates a problem for administering the PIRP in that the ISO must use meteorological data to forecast the resource's future output. This is not an issue if a resource outside the ISO's balancing authority area, which wishes to participate in PIRP, is a pseudo-tie. If a resource that uses a dynamic schedule wishes to participate in PIRP, it must commit to schedule 100% of its output to the ISO during the period in which it is in PIRP.

Scheduling and netting rules

This proposal does not change the current rules for PIRP scheduling and netting. SCs of PIRs will continue to schedule in HASP in accordance with the hourly energy forecast provided by the ISO. If resources comply with these rules they will not receive imbalance energy charges for deviations across each 10 minute settlement interval. Instead the energy deviations will be netted across a calendar month and settled at a weighted-average price.

Cost allocation

Currently, PIRP uplifts are allocated to net negative uninstructed deviations, but RI-MPR Phase 1 changes the allocation so that uplifts (i.e., the cost difference between PIRP settlement and 10-minute settlement) are allocated to (1) the SC of the LSE buying PIRP energy in proportion to the contracted output of the resource in the Master File for existing PIRs or (2) the assigned SC for new PIRs.

To recap, the following settlement charge codes are relevant in this process:

- Charge code 6470 - *Real-time instructed imbalance energy settlement* – This is calculated on a 10 minute settlement interval and resource level basis. Instructed energy for a PIR is paid in settlements charge code 6470 at the resource-specific LMP.

- Charge code 6482 – *Real-time excess cost for instructed energy payment* – This is calculated on a 10 minute settlement interval and resource level basis. It is the excess cost (resulting from a price shortfall between the bid price and resource-specific LMP) corresponding to exceptional dispatch energy settled in 6470 and is paid in settlements charge code 6482.

- Charge code 6486 – *Real-time excess cost for instructed energy allocation* – This is calculated on a 10 minute settlement interval basis. The charge code 6482 payment costs are allocated in charge cost 6486 to net negative deviation during the settlement interval.

- Charge code 6475 – *Real-time uninstructed imbalance energy settlement* - This is calculated on a 10 minute settlement interval and resource level basis. The payments or charges attributable to uninstructed energy for all resources are calculated in this charge code.

- Charge code 711 – *Intermittent resources net deviation settlement* – This is calculated on a monthly basis. It is the uninstructed deviation for each PIR netted over the settlement month and charged/paid to the resource based on the weighted average price of their generation over the settlement month.

- Charge code 721 - *Intermittent resources net deviation allocation* – This is calculated on a monthly basis. It is the total of the payment costs calculated in charge codes 6475 and 6486 for PIRs netted over the settlement period minus the total in charge code 711. Charge code 721 is allocated to each business associate based on its net negative deviation for the trading month. This is the only charge type that will be affected by this proposal.

The ISO proposes to allocate PIRP settlement uplifts to the SCs identified in the eligibility process. This approach means that scheduling coordinators who have not agreed to these uplifts will not be allocated these costs. The following example illustrates how costs are allocated today and how this allocation will change.

In this example there are 5 SCs in the market.

Table 1

Scheduling Coordinator	Portfolio contains PIRs?
A	PIRs
B	PIRs
C	No PIRs
D	No PIRs
E	No PIRs

The total PIRP share of uninstructed imbalance energy and instructed imbalance energy deviation amount is $120,000 (CC6475 and CC6486) in the sample month. Per the tariff, a two tiered allocation occurs, first to the PIRP monthly net negative deviation in CC711 and then to negative deviation across the market in CC721. Each PIR's accrual is as follows:

Table 2

Resources	UIE (cc6475)	IIE (cc6486)	Accrual Amount
PIR A	$60,000	$12,000	$72,000
PIR B	$40,000	$8,000	$48,000
Total PIR Share Monthly Deviation	$100,000	$20,000	$120,000

Table 3 below describes the CC711 allocation for the PIRs. The generation amounts, dollars and the deviation quantity are all assumed in this example, not calculated.

Table 3

SC of PIR resource	Total monthly generation - MW (a)	Total monthly generation - $ (b)	Monthly settlement LMP (c = b/a)	Monthly negative deviation quantity - MW (d)	Monthly deviation settlement - $ (e= c x d)
A	9,000	$160,000	$17.78	843.75	$15,000
B	7,500	$350,000	$46.67	750	$35,000
Total					$50,000

Today the remainder of the total $120,000 PIR deviation, $70,000, ($120,000 – $50,000 = $70,000), is allocated to all SCs as illustrated in Table 4 below. **For the sake of simplicity, the example assumes that all the resources are existing PIRs, not new ones.** In this example the allocations will go to the SCs of the LSE that contracted with the PIRs.

Table 4

Scheduling Coordinator	PIR in Portfolio	Negative deviation quantity – MW (c)	Monthly negative deviation price - $ (d)	Monthly deviation allocation amount - $ (e = c x d)
A	PIR	843.75	$ 9.87	$8,325.99
B	PIR	750	$9.87	$7,400.88
C	No PIR	500	$9.87	$4,933.92
D	No PIR	2,000	$9.87	$19,735.68
E	No PIR	3,000	$9.87	$29,603.52
Total		7,093.75		$70,000.00

In this proposal the $70,000 will be allocated only to SCs of LSEs that contract with PIRs based on the amount of generation provided by each PIR in that month.[7] The allocation is described in the following table. Each PIR's deviation allocation amount in this table is the difference between their total accrual amount (Table 2) and their monthly settlement deviation amount (Table 3).

Table 5

Scheduling Coordinator of LSE contracting with PIR	PIR	Total monthly gen – MW	Deviation allocation amount	Monthly deviation allocation price - $
A	PIR (A)	9,000	$ 57,000	$6.33
B	PIR (B)	7,500	$13,000	$1.73
Total			$70,000	

Note that the price that the SC for LSE A is paying for PIR (A) is much higher than the price SC for LSE B is paying for PIR (B). In the event that one PIR resource serves multiple LSE's, the deviation amount will be allocated pro-rata based on the contracted MW or percentage in Master File.

[7] Note that one PIR could potentially contract with more than one LSE for its output so the master file will reflect the number of MW or percentage of MW assigned to each LSE.

2.4 Other recommendations for updating PIRP

During the stakeholder process there were some other suggestion on improving PIRP – (1) allowing decremental bidding with PIRP and (2) suspending PIRP netting when prices are negative. The ISO agrees that allowing decremental bidding with PIRP could benefit the ISO by providing more flexibility when there is a need to curtail generation. As we have mentioned in previous proposals and presentations this change would impact a number of systems and could not be implemented within the RI-MPR Phase 1 timeframe, however, this idea will be fully explored as a RI-MPR Phase 2 mid-term enhancement.

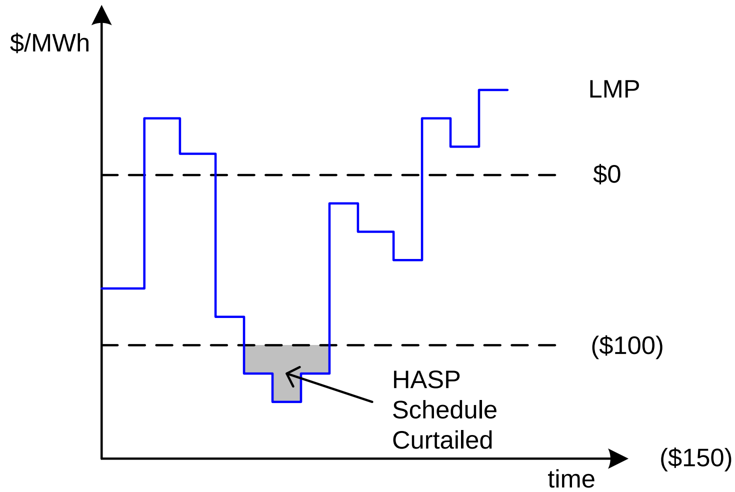
In their comments both SMUD and CalWEA advocated suspending PIRP when prices are negative. Each proposal was slightly different. SMUD proposed in their comments to suspend PIRP in intervals when prices are negative; CalWEA recommended suspending PIRP when the weighted average LMP during the hour is negative. The idea is that this would benefit the ISO by incenting resources to curtail when the price is negative while maintaining the PIRP netting benefit to PIRs (in positive intervals).

The ISO considered these proposals very carefully and determined that from an operational perspective this change could have a detrimental rather than beneficial impact to system reliability. Suspending PIRP during negative prices could indeed incent PIR resources to curtail, but it could also cause fluctuations in MWs when prices (perhaps in the next interval) are positive. The price chasing incentive could lead to system instability. Based on this understanding, this option was not included in the PIRP proposal.

2.5 Decremental Bidding Option

During the stakeholder process some stakeholders have suggested adding the ability of PIRs to provide economic bids. While this option may increase the amount of decremental bids, it would be a significant undertaking from an implementation standpoint. The logic that is currently in place does not support self schedules and bidding simultaneously. The current end-to-end solution assumes that energy below a self schedule is a penalty protected area which is not biddable and that this energy is a price taker which would not be included in bid cost recovery. The ISO's project office evaluated making a change to provide for economic bidding with PIRP self scheduling and determined SIBR, RTM, MQS, SaMC and OASIS would be impacted. Given the implementation challenges, this is a change that the ISO is considering as an intermediate term enhancement in the renewable integration market and product review. The ISO plans to begin a market design initiative on this as early as Spring, 2012. In the meantime, there is the ability for a PIR to provide economic bids in the real-time market during periods when negative prices are expected as described below.

In lieu of submitting a HASP self schedule in hours when they believe that the price will be negative, the following example shows how a PIR could submit incremental bids with a negative price.[8]



An 80 MW PIR resource believes that prices in an upcoming hour will be negative. Their PIRP forecast is 50 MW for that hour. Assume that the opportunity cost for this resource is -$100 and the energy bid floor is -$150/MWh. The resource submits a bid for 45 MW at a price of -$100. If the LMP is less than their bid (-$100) the resource will be dispatched to 0 MW and they will be paid to decrement. If the LMP is greater than -$100, the resource will be dispatched to 45 MW and will be paid the LMP. In this way they are maximizing their output until the LMP is greater than their opportunity cost.

2.6 Convergence Bidding Option

Another option currently available to resources outside of the PIRP paradigm is convergence bidding. The implementation of Convergence Bidding has increased the ability for VERs to participate in the day-ahead market and manage their risk due to high forecast errors. The highest risk for VERs is negative real-time deviations during periods of high prices. When VERs actual output is below their day-ahead schedule, the additional supply which must be procured in real-time can lead to higher prices than day-ahead. Since a VER has a negative marginal cost which exceeds the current bid floor, the need to minimize risk of exceeding their day-ahead schedule during low prices is a lesser risk. In addition, a newer VER has the capability to stop generating, whereas the VER cannot increase their fuel supply when the sun isn't shining or the wind isn't blowing. So when the bid floor is reduced beyond their negative marginal cost, the resource can manage this risk by submitting DEC bids in the real-time market.

Example: Assume a VER has a 100 MW day-ahead forecast with an error of +/- 25%. In order to hedge their exposure to real-time prices if the resource has negative deviations, the resource submits a virtual demand bid equal to the negative forecast error or 25 MW at the same generation location. The 25 MW virtual demand bid is liquidated at the real-time LMP and

[8] Deviations in these hours will not be included in the monthly netting since resource is not in PIRP.

protects the resource from exposure to the real-time price for their forecast error. If the resource generates above 75 MW the resource benefits from the higher real-time price.

3 Energy Bid Floor

3.1 Introduction

The ISO spot markets currently require that the economic bids submitted by scheduling coordinators to buy and sell energy be no greater than the cap of $1,000 per MWh and no less than the floor of -$30 per MWh. Negative bids serve an important function in the spot markets; among other things they are used by supply resources to elicit payments to decrement their energy production from previously scheduled levels, and by demand (including exporters) to increase their energy purchases from the market at times when there is excess supply. There is currently a limited supply of decremental energy bids to enable the ISO market systems to economically reduce energy supply to balance demand when needed, especially in off-peak hours that will become increasingly susceptible to much higher levels of over-generation as additional renewable production comes on-line.

The key objective of this proposal is to provide price signals to incent resources to submit decremental bids. Although some resources are constrained based on contractual and environmental factors and do not have the flexibility to adjust their output during over-generation situations, there are other resources that simply cannot reduce output economically given the current energy bid floor. In particular, the current bid floor level of -$30/MWh is not sufficient to compensate reductions in energy output from VERs who receive additional revenues outside of the ISO markets for their energy production and does not allow SCs for these resources to bid economically in many cases.

Market design changes to increase the provision of decremental bids are an important element of the present initiative, to improve the ISO's capability to use market-based optimization to manage over-generation conditions, real-time congestion and possibly system ramps in the future. If there is not a sufficient supply of decremental bids in any of these conditions, the ISO must issue non-economic instructions (i.e., instructions that are not based on energy bids) for resources to reduce energy supply to balance the system.[9] For a number of reasons these non-economic dispatch instructions result in less efficient curtailment of resources. Such instructions are determined by the market optimization through the use of market parameters that are outside the allowable range of economic bids and hence may result in decremental dispatch of plants with higher willingness to pay to remain in operation.[10] Over the past year, the ISO has faced numerous instances where there were insufficient decremental bids in the market, thereby indicating that a reduction in the bid floor is needed even in the near term. Most recently

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9 This section is written from the perspective of supply resources to simplify the discussion. It should be understood, however, that the energy bid floor is also relevant to demand resources, including both internal load and exporters that may be willing to increase their purchases of energy to relieve over-generation if the price were low enough.

10 For example, New York ISO has noted in comment on the FERC Notice of Inquiry Seeking Comment on the Integration of Variable Energy Resources that negative LMPs in the absence of sufficient decremental bids has caused wind plants to curtail at higher quantities than would have been necessary if the decremental dispatch was conducted through the economic dispatch function of the ISO. (http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/04/NYISO_Cmmnts_VERs_NOI_041510.pdf)

instances of over generation with lack of decremental bids to help manage congestion on the grid more effectively and economically have increased in frequency and are expected to increase over time with the addition of VERs in the next 2-3 years, particularly in high hydro conditions, thereby making such changes an even higher priority.[11]

The original reasoning which supported setting the energy bid floor at -$30/MWh, as articulated in prior filings and FERC orders, did not take into account the effects of renewable energy credits or production tax credits on a resource's opportunity cost and, hence, a unit's likely unwillingness to reduce its output for a payment of only $30/MWh. For more background regarding the history for setting the bid floor at -$30/MWh, refer to the Issue Paper which provides a detailed breakdown.[12]

3.2 Proposal

The ISO modified its previous proposal of -$300/MWh and now recommends a staged approach to lowering the energy bid floor. Many stakeholders expressed concerns about the potential consequences of making a change of this magnitude, so instead we propose to lower the floor to -$150/MWh initially and in the following year lower the floor again to reach -$300/MWh in the same manner that the ISO increased bid cap as a result of FERC's July 1, 2005 Order on the Comprehensive Market Redesign Proposal. In that Order, FERC required the ISO to set the bid cap at $500/MWh and then:

> *Twelve months after MRTU implementation, the energy bid cap shall automatically be increased to $750/MWh, unless the CAISO makes a filing with the Commission showing that its markets are non-competitive and the Commission supports this assessment. This process will be repeated twelve months later, and the bid cap will automatically increase to an ultimate level of $1000/MWh, unless the Commission supports the CAISO's analysis that the markets are non-competitive.*[13]

We can also look at how the ISO implemented position limits for convergence bidding for the same type of treatment. In its October 15, 2010 Order on convergence bidding FERC accepted the ISO's proposal to institute position limits that are automatically changed on a pre-set schedule

> *If, based on input provided by the DMM and MSC and on its own analysis, CAISO concludes that if it is not appropriate to make the position limits change it will timely*

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11 An indication of the frequency of decremental bid insufficiency is found in Table 4-1 in the 20% RPS Study, (http://www.caiso.com/23bb/23bbc01d7bd0.html) which shows the number of 5-minute intervals with negative prices by season and hour of day from April 1, 2009 to June 30, 2010.

12 "*Issues Paper* – Renewable Integration Market and Product Review Phase 1, September 30, 2010" - http://caiso.com/27be/27beb7931d800.html

See ORDER ON FURTHER AMENDMENTS TO THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR'S COMPREHENSIVE MARKET REDESIGN PROPOSAL (Issued July 1, 2005) at: http://www.caiso.com/Documents/OrderonFurtherAmendments-ISOComprehensiveMarketRedesignProposalinDocketNo_ER02-1656-026_Amendment44_.pdf *make a filing with the Commission to modify the percentage level and/or timetable for the upcoming change.*[14]

There are a number of data points that the ISO used in determining the appropriate amount that the energy bid floor needed to accommodate:

- Renewable energy credits (RECs) are capped at $50/MWh.
- Tax credits for wind production along with other tax incentives guarantee these resources payments of close to $37/MWh. The renewable energy production tax credit (PTC) alone, currently at $21/MWh,[15] is the primary federal incentive for wind energy and has been essential to the industry's growth.
- The FERC Electric Quarterly Reports (EQR) filed by sellers in the ISO area for the 4th quarter of last year reported prices greater than $150/MWh for energy sales during that period.[16]
- Additionally, the CPUC confirmed that a recent RFO issued for solar photovoltaic facilities had a cap of $295/MWh.
- Contract penalties associated with curtailing energy production places additional pressure on VERs to produce rather than decrement their energy.

The appropriate floor must be low enough to incent resources with these types of payments to curtail their production. It is our understanding that the average payment for a wind resource is somewhere in the range of $130/MWh so lowering the floor to -$150/MWh will cover the opportunity costs for an average resource. However, significant amounts of solar generation are scheduled to come online in the near future so the step down to -$300/MWh is appropriate to cover the opportunity costs for these resources. The ISO will monitor the effects of the reduced bid floor during the first year and if necessary will re-evaluate moving to the -$300/MWh level.

3.3 Additional analysis

Some stakeholders also voiced concerns that the majority of negative prices that occur in the current market are driven by uneconomic parameters (power balance constraint) rather than decremental bids. They suggested that lowering the bid floor will not incent additional decremental bids but rather increase the incentive to self-schedule. Based on this concern, ISO staff assessed how often these conditions occurred. Between April 2009 and October 2011 just over 2,300 out of a total of 14,587 negative 5 minute intervals (or approximately 15%) were due to relaxing the power balance constraint. This data reveals that only a small portion of the negative prices since MRTU start up were due to relaxing the power balance constraint.

Stakeholders also requested updated analysis regarding the duration of negative pricing episodes. The concern was that negative prices were fleeting, lasting a single interval or two intervals in many cases. They suggested that lowering the floor bid floor would discourage participation in the real-time due to these unpredictable movements in price. The ISO reviewed

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14 The convergence bidding order can be found at: (http://www.caiso.com/Documents/October15_2010Orderdirectingcompliancefilingandgrantingwaiverrequestindocketno_ER10-1559_convergencebidding_.pdf),."(para. 117)

15 The renewable energy production tax credit is an income tax credit of 2.1 cents/kilowatt-hour and is allowed for the production of electricity from utility-scale wind turbines. This incentive was created under the Energy Policy Act of 1992. Through the American Recovery and Reinvestment Act (ARRA), Congress acted to provide a three-year extension of the PTC through December 31, 2012.

16 The FERC EQR reports are located at: http://www.ferc.gov/docs-filing/eqr.asp

the same timeframe noted above and found that out of 14,587 negative 5 minute intervals, only 1342 were single intervals of negative prices (meaning the interval before and after were positive) and there were 581 incidents where the negative prices that spanned two intervals.

4 Bid Cost Recovery

4.1 Proposal Overview

Bid cost recovery (BCR) is the process by which the ISO ensures that scheduling coordinators are able to recover start up, minimum load costs and bid costs for generating units, system resources (resources located outside of the ISO balancing authority area) and participating loads. Currently, the BCR calculation is performed over the entire trade day and netted across the DA and RT markets for that trade day.

The ISO's proposal is to change the bid cost recovery rules so that netting occurs separately for the day-ahead and real-time markets. This change is an important element of the RI-MPR Phase 1 Straw Proposal because it helps align incentives to provide economic bids in the real time market which is vital to managing the grid reliably as more VERs come into the ISO control area's fleet of generating resources. Offsetting day-ahead and real-time market outcomes can lower a resource's BCR if there is a surplus in day-ahead to net out portion of the shortfall of the real-time market and would alter the alignment of price incentives targeted in this initiative. In particular, this misalignment would discourage economic bids in the real time market. Thus the netting of costs and revenues across day ahead and real time (i.e., the current BCR structure) is at odds with the intent of the proposal to lower the Energy Bid Floor because it dilutes the incentive for decremental bids in the real-time. Without this proposed change to the BCR rules, the RI-MPR Phase 1 proposal would have the undesirable result of hampering the ISO's ability to manage the grid given the increasing number of VERs on the system. Revising the current netting methodology for bid cost recovery during this phase of the Renewable Integration initiative is important because it cushions the risk of bidding in the real time market and so it lessens the incentive to self schedule.

As a brief summary:

- The ISO proposes to revise its rules for netting costs and revenues for performing its bid cost recovery calculation so that day-ahead costs and revenues are no longer netted against RUC and real-time costs and revenues;
- The ISO also proposes to retain the daily netting of costs and revenues across the 24 hours of the day-ahead market;
- As is currently the case, the ISO proposes that minimum load costs will be offset by the minimum load energy revenues from the same market;
- No changes are proposed to the accounting of start-up and MSG transition costs with the exception of short-start units with a real-time ISO dispatch that is delayed from but overlapping with the day-ahead commitment; and
- The ISO proposes to apply a performance metric which will scale components of the bid cost recovery calculation based on the portion of the deviation from ISO dispatch. This performance metric will replace the day-ahead and real-time MEAF and the tolerance band for minimum load costs.

- The ISO proposes to additionally refine the performance metric with a real-time persistent UIE check which will disqualify real-time energy from the real-time bid cost recovery in the case of persistent real-time deviations.

4.2 Benchmarking against other ISOs

Research of ISO/RTO practices indicates that the New York ISO (NYISO), the PJM Interconnection, the Midwest ISO (MISO), the Electric Reliability Council of Texas (ERCOT), and the New England ISO (ISO-NE) net their forward and spot markets separately.[17] Analyses of their tariffs and business practice manuals indicate that no netting across day-ahead and real-time markets is performed in those markets when calculating uplift payments.

With respect to New York, the philosophical intent from the inception of the market has been to separate the day-ahead and real-time bid cost recovery so as to provide efficient incentives for generators and others to follow the real-time dispatch. To address the problem of generators that collect uplift on their day-ahead schedules and then trip off line, the current market rules in the NYISO provide for a proration of day-ahead start up costs based on actual minimum load output as opposed to scheduled minimum load output.

Both the NYISO and the MISO have a settlement mechanism (called the Day-Ahead Margin Assurance Payment, or DAMAP in the NYISO), which basically guarantees a generator its day-ahead margin to the extent it is uneconomically dispatched down in real-time. The DAMAP rules are set to make sure that units that are not dispatched down but are negatively deviating are not covered. The DAMAP rules also exclude generators that raise their offers between day-ahead and real time, both in the hour in which the bid changes and hours before and after.

4.3 Performance metric for day-ahead and real-time energy bid costs and minimum load costs

In the fourth revised straw proposal on the RI-MPR Phase 1 initiative, the ISO recommended to base day-ahead bid costs on scheduled amounts versus delivered amounts, i.e., not apply the day-ahead metered energy adjustment factor (MEAF) in the DA BCR calculations. The rationale for this proposal was that it was consistent with the ISO's proposal to eliminate the netting of costs and revenues in DA against those in RUC and RT. Removing the netting severs the connection between the two markets for the purpose of BCR calculations. One of the stated goals in this initiative is to ensure that bid cost recovery provides the proper incentive for the targeted bidding behavior. As discussed above, to limit disincentives to submit economic bids in the real-time, it is import to decouple the markets and eliminate the netting of costs and revenues across markets.

In its 2006 order enabling the ISO's new nodal market design, the Federal Energy Regulatory Commission stated "*[r]esources that fall short of day-ahead dispatch instructions should only be*

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17 The following links provide information regarding the netting practices of other ISOs surveyed. NY ISO - Billing and Accounting Workshop Presentation - http://www.nyiso.com/public/webdocs/services/market_training/workshops_courses/accounting_billing/billing_acctg_oct2009rev3.pdf; MISO - Tariff section 39.2.9 and 40.3.5, and Business Practice Manual Market Settlements Attachment C http://www.midwestiso.org/publish/Folder/20f443_ffd16ced4b_-7fe50a3207d2?rev=6; PJM - Tariff section 5.2.1 http://pjm.com/~/media/documents/agreements/oa.ashx; ISO NE - III.F.2.1.14 and III.F.2.1.4 which is appendix F of the tariff http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-f.pdf

guaranteed the recovery of costs associated with the energy actually provided, and should not receive payments for deviations from dispatch instructions." Accordingly, the ISO provided bid cost recovery for only those portions of the day-ahead market that were actually delivered. The concern with this, however, is that providing resources with bid cost recovery for delivered energy may have an incentive to deliver more energy. Operation of the grid under increasing variability of generation necessitates economic incentives to elicit the maximum flexibility from the fleet of flexible and responsive resources. To achieve the targeted incentives, the ISO proposes to change its market rules to no longer net between the DA and RUC/RT markets, to eliminate the day-ahead and real-time MEAF, and to apply a performance metric and a "persistent uninstructed energy check" in the case of deviations from ISO dispatch. The performance metric will consider the ratio of metered and *dispatched* energy rather than metered energy relative to the resource's *day-ahead schedule*. The persistent uninstructed energy check will identify blocks of intervals with persistent deviations from dispatch.

This proposal reflects the ISO's recognition that there can be adverse incentives created by eliminating entirely the impact of real-time performance on the calculation of bid cost recovery. The performance metric is essentially a fraction by which components of the bid cost recovery calculation are scaled. The fraction is the deviated portion of the real-time dispatch by which the resource actually over- or under-delivered. With this change, the day-ahead and real-time **net costs** or **net revenues** in the bid cost recovery calculation will be scaled by the performance metric. It is important to note that this applies to over-delivery as well as under-delivery of energy relative to ISO dispatch. Therefore, the performance metric will impact a resource that over-delivers as well as one that under-delivers. This is important especially in the effort to integrate renewable resources; aligning incentives to meet <u>and</u> not to exceed ISO dispatch is critical to reliably managing the grid in situations of highly variable generation and in situations of over-generation. Such situations are expected to occur more frequently as the ISO fleet contains increasing capacity from variable energy resources.

The ISO is proposing that the performance metric (PM) be calculated per resource and per settlement interval in the following manner:

$$Performance\ Metric = \min\left\{1, \left|\frac{Metered\ Energy - Regulation\ Energy}{Total\ Expected\ Energy} - 1\right|\right\}$$

Note that regulation energy is "deemed delivered" since it is provided by a resource under the ISO's control via direct electronic signal. For this reason, regulation energy is excluded in the performance metric calculation. Furthermore, and for the same reason, regulation energy is not included in the calculation of total expected energy. And so, by subtracting regulation energy from metered energy in the performance metric formula, it is ensured that the numerator and denominator are capturing like terms.

That PM value is then applied to adjust the cost and/or revenues (as described below) in the day-ahead BCR calculation, as well as in the real-time/residual unit commitment BCR calculation. The following table shows the quantity, either costs, revenues or both depending on the signs of their values to be adjusted under the PM approach.

Table 4.3(a): Application of the performance metric

Costs *	Revenues	Apply PM to…

+	+	Costs
+	–	Costs & Revenues
–	+	n/a
–	–	Revenues

* Energy bid costs and minimum load costs only.

Examples are provided as an attachment to this proposal.

Furthermore, the ISO proposes the following performance metric boundary to avoid an undue negative impact of the performance metric in cases of small incremental dispatches. The importance of this boundary is that it prevents the scaling of energy bid costs and minimum load costs for very small deviations from dispatch that may legitimately be due to ramping constraints or other such operational constraints.

$$\sim if \sim$$
$$|Metered\ Energy - Regulation\ Energy - Total\ Expected\ Energy| \leq 5/6\ MWh$$
$$\sim or \sim$$
$$Performance\ Metric\ \leq 3\%$$
$$\sim then \sim$$
$$Performance\ Metric\ is\ not\ Applied$$

The threshold values of 5 MWh and 3% (see footnote[18]) are consistent with our experience with realistic and justifiable deviation around dispatch and the ISO has employed the "5 MWh or 3%" thresholds even prior to the launch of the LMP market in April 2009. The ISO has used these thresholds for other operating performance by a generating resource such as when the plant-level or configuration-level minimum operating level has been achieved. These values also reflect justifiable deviations that result from the modeling of resource ramp rates as four-segment "curves" rather than as continuous or smooth curves as they are in actuality. In addition to the threshold value, the performance metric will not be calculated during the startup, shutdown and MSG transition periods as long as they perform. This is out of recognition that a unit cannot control exactly the output of the resource during startup, shutdown, and MSG transition periods. Although again, these values are based on experience to-date, the ISO will continue to assess the appropriateness of these thresholds.

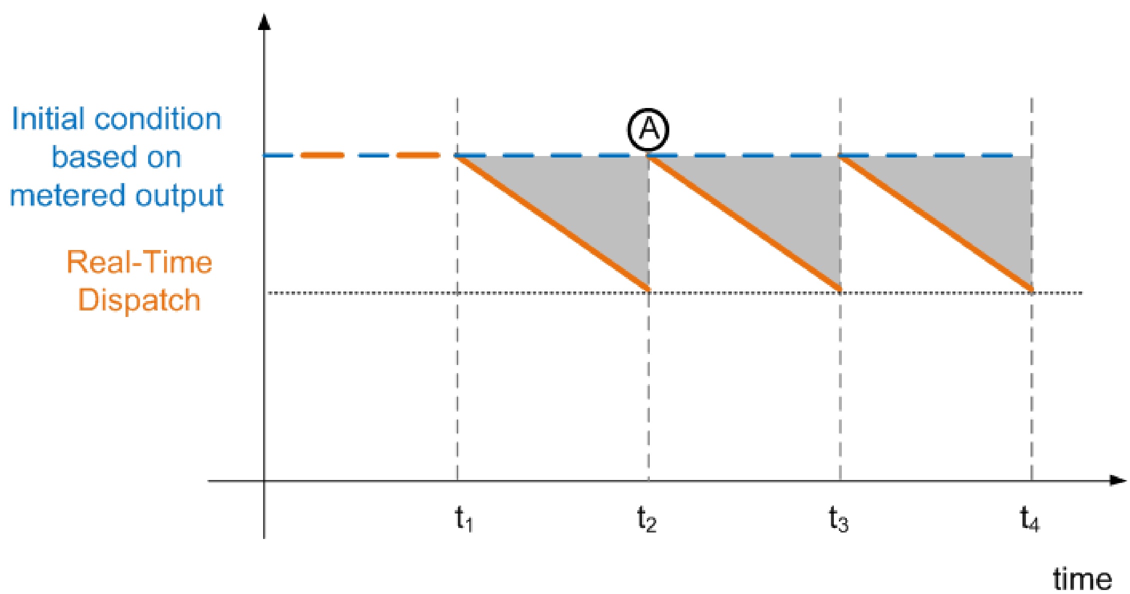
18 When 3% has been used in the past as a threshold for resource operating performance, the value was actually calculated as 3% of the Pmax of the resource. In this proposal, the 3% threshold is the outcome of the calculation of the performance metric. It is not tied strictly tied to resource operating characteristics, therefore. Although there are merits to tying the performance metric threshold directly to resource operating characteristics – simplicity definitely being one – there are also drawbacks. Specifically, a large resource (for example 800MW) would have a tolerance band of 24 MW which the ISO proposes is too large a deviation to be accommodated within a tolerance band.

4.3.1 Persistent uninstructed energy check

The performance metric described above scales components of each interval's bid cost recovery calculation when a resource is deviating from its ISO dispatch. However, the PM may not fully remove certain incentives to inflate BCR payments for reasons explained below. In particular, there is the possibility that a generating resource can deviate *persistently* from the real-time ISO dispatch and inflate its BCR payments.[19]

Under the current ISO tariff, a resource's real-time uninstructed energy is not considered for bid cost recovery in settlement intervals associated with deviations from ISO dispatch instructions of the same interval. However, real-time dispatch uses a resource's telemetry value[20] as the basis for deriving the resource's initial condition. Therefore, if a resource's dispatch is ramp-constrained in an interval, then the uninstructed deviations of the generator in previous intervals will have a cumulative effect on the amount of energy of the current settlement interval that is subject to bid cost recovery. Figure 4.3.1(a) below provides a depiction of the persistent deviation strategy.

Figure 4.3.1(a): Persistent deviation from real-time ISO dispatch



In the diagram above, the ISO real time dispatch is depicted by the solid orange line, and the generator response (that is, the projected initial condition based on the metered output) is depicted by the dashed blue line. The ISO dispatch at t_1 is not followed and so, at t_2, the ISO issues a new dispatch from projected initial condition rather than from the targeted output based on the t_1 dispatch. The diagram above shows this strategy being employed three times in a row. In this scenario, the ISO was trying to dispatch the resource down which indicates that the LMP was likely below the resource's energy bid price. By ignoring the ISO dispatch instructions and knowing that the ISO dispatch would be based on telemetry, the resource has essentially achieved to be perpetually dispatched at some

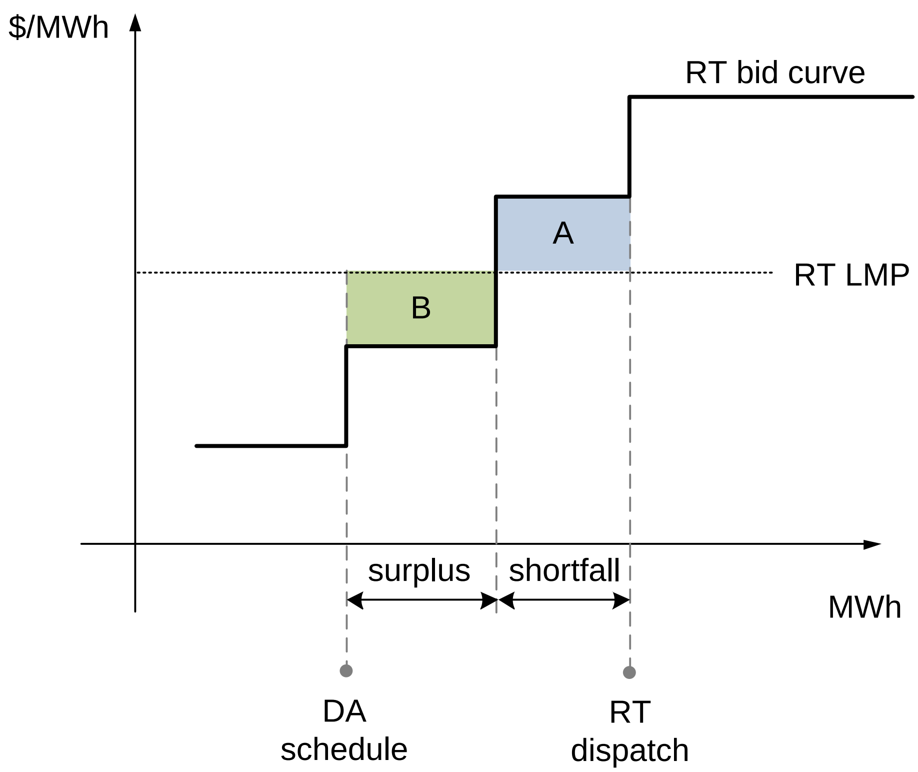
[19] The potential for this practice was pointed out by SCE in their comments on the 5th revised straw proposal.

[20] Telemetry refers to either actual telemetered value or state-estimator value.

uneconomical level, thereby strategically expanding the energy bid cost portion of their BCR calculation from what would have been should the resource follows the ISO dispatch instruction.

The figure below explains the practice from the perspective of the bid curve. Telemetry indicates that the generator MW is at highest bid segment level where the bid price exceed the LMP. ISO real-time dispatch dispatches the generator downward to the breakpoint between the two highest bid segments. The DA schedule is at the breakpoint between the two lowest bid segments. The real-time dispatch level is above the DA schedule and the real-time energy is incremental. Given that the LMP is between the bid prices of the second and the third highest segments, the incremental energy associated with the second highest segment incurs shortfall as given by area A and similarly the incremental energy associated with the third highest segment incurs surplus as given by area B. Consider that area A exceeds area B. The generator will receive BCR uplift payment. Should the generator follow the dispatch instruction for the current and the subsequent time intervals, the generator should be dispatched down to the breakpoint between the second and the third segments at which all incremental energy are surplus in BCR accounting. However, should the generator not respond to the dispatch instructions and remains at its current MW level, real-time dispatch will continuously dispatches the generator to the level at shown in the diagram and such that the generator will receive uplift payment for all these intervals.

Figure 4.3.1(b): Quantifying and decomposing real-time shortfall and surplus



The potential for the practice of deviations described above is not created by the fundamental proposal to remove the netting of bid cost recovery across the day ahead and real-time markets. It would, however, be exacerbated by the separation of the netting. Thus, the ISO proposes a refinement to the interval-by-interval performance metric which, on its own, would not otherwise fully measure the amount of uninstructed energy associated with the persistent deviation because the ISO's dispatch is based in part on a resource's actual output, which may reflect uninstructed output.

The proposed refinement, termed the persistent uninstructed imbalance energy (UIE) check, will employ an algorithm that defines a state variable for each time interval to accumulate the amount of past uninstructed deviation in energy that can result in uneconomic energy and such accumulation is limited by the maximum amount of energy that can negatively impact the netting between revenue and cost. In essence, the state variable of a given interval represents the interval uneconomical energy amount caused by the past uninstructed deviations UIEeffect,i(MWh). Using such a scheme, for each settlement interval, the shortfall dollar amount of the uneconomical energy as given by the state variable is calculated, as UIEbcr,i($)and in the meantime also calculated is the shortfall dollar amount under the current tariff for the actual uneconomical energy UNENbcr,i($).

Then these two per time interval dollar quantities UIEbcr,i($) and UNENbcr,i($) are aggregated over a certain period of time.UIEbcr($) and UNENbcr($). Such period of time can be the entire day or a period of contiguous time intervals where the RT instructed energy are all in either incremental or decremental. We also aggregate the uneconomical energy amount represented by the state variable over such period as UIEeffect,(MWh).

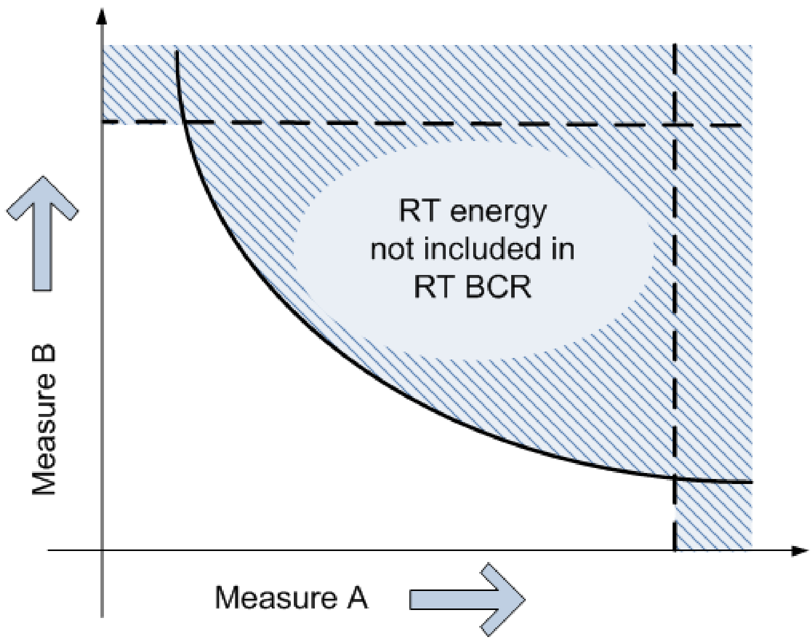
Two measures A and B are formulated using these three aggregated quantities.

1. Measure A is the ratio between the aggregated shortfall of uneconomical energy caused by the uninstructed deviation in real-time, i.e. the state variable value, and the aggregate shortfall of the actual uneconomical energy (UIEbcr($)/UNENbcr($)). The measure captures the persistency of the uninstructed deviation behavior that results in shortfall in BCR calculation.
2. Measure B is a $/MWh rate of the shortfall per MWh of uneconomical energy by uninstructed deviation which is the ratio between UIEbcr($) and UIEeffect,(MWh). This measure captures the per-MWh impact on BCR from the UIE cumulative effect.

For the period of contiguous time intervals for consideration, if BCR shortfall in energy is determined to be the case under the current BCR scheme, then these two measures will be evaluated in concert. In this way, the proposal seeks to avoid disqualifying real-time energy from real-time bid cost recovery calculations when the pattern of deviations is short and/or does not generate a large shortfall in energy revenues.

Graphically, the threshold is governed by a trade-off curve is depicted below. If the point defined by the evaluated values of measure A and B falls in the blue, cross-hatched area, the real-time energy are not included in the real-time bid cost recovery calculation for that period of intervals.

<u>Figure 4.3.1(c)</u>: Persistence and $/MWh Rate of UIE Effect Threshold



Measure A measures the degree of persistency of the uninstructed deviation by a generator. If this measure exceeds the threshold value of the vertical line, energy will be disqualified from BCR irrespective to measure B. On the other hand, for measure A at some value to the left of the vertical line, disqualification only apply when measure B value is above the value as given by the trade-off curve.

The values of the trade-off curve used as the threshold for the persistent uninstructed deviation check will be developed by considering analysis of past market outcomes as well as analysis of counter-factual situations. These threshold values will need to be specific to different types of resources to as to ensure that they fairly reflect the actual operational parameters. Threshold values that are too loose can enable resources to gain undue cost recovery when they are persistently deviating from the ISO dispatch. On the other hand, threshold values that are too tight can unduly disqualify energy bid costs from real-time bid cost recovery calculations and thus may discourage the submission of real-time energy bids. Extensive analysis and stakeholder will be necessary to determine the appropriate tolerance values upon approval of this high-level design.

The CAISO is concerned that a generator could employ a strategy in upward uninstructed deviation to position itself at MW level that takes more than one RTPD interval to ramp down the minimum load level for shutdown. As such, the generator is able to avoid a economic shutdown instruction issued by the ISO and continues to be online at level above the minimum load. Under the current tariff, generator will receive the bid cost recovery for the generator's minimum load cost. The CAISO is currently looking into methodology to detect such behavior and upon being detected to be such a case, the generator will also be disqualified from the bid cost recovery of the minimum load cost.

4.4 Proposed accounting of energy bid costs and minimum load costs

The ISO proposes to observe the following four rules in accounting for **energy bid costs**:

1. <u>No change from the previous proposal</u>: A resource's day-ahead energy bid costs and energy revenue are included in the day-ahead BCR calculation;

2. No change from the previous proposal: Residual unit commitment (RUC) capacity bid costs, real-time energy bid costs, RUC capacity payment, and real-time energy revenues go into the real-time BCR calculation; and

3. No change from the previous proposal: The performance metric (and the performance metric boundary as applicable), as defined in the previous section, will be applied to day-ahead and real-time energy bid costs.

4. New element of the proposal: For incremental real-time intervals flagged by the persistent UIE check, the resource is not eligible for real-time energy bid cost recovery for contiguous incremental intervals. The same rule will be applied in the case of decremental uninstructed energy.

The ISO proposes to observe the following five rules in accounting for **minimum load costs**:

1. No change from previous proposal: For non-MSG resources and MSG resources with the same day-ahead and real-time configurations, the ISO proposes that minimum load costs be calculated the same as they are today. That is to say, the market of the minimum load costs will always be aligned with the market of the minimum load energy;

2. No change from the previous proposal: For MSG resources with different day-ahead and real-time configurations, the ISO proposes that real-time minimum load costs (MLC) be calculated as the incremental change in minimum load costs between day-ahead and real-time. That is to say,

   $$RT\ MLC = RT\ Configuration\ MLC - DA\ Configuration\ MLC$$

   With the inclusion of this rule, real-time minimum load costs can be negative if the resource is committed in real-time to a lower configuration.

   Examples are provided as an attachment to this proposal.

3. No change from the previous proposal: The ISO will account for negative minimum load costs when a unit is completely de-committed to off-line in real time from its day-ahead schedule. This rule is proposed to account for the associated negative minimum load cost and this rule will be applicable both MSG and non-MSG resources.

   Currently, in the case of an economic de-commitment in the real-time, the decremental energy between the resource's day-ahead schedule and zero is charged at the real-time LMP. However, the decremental energy between Pmin and zero does not have a bid cost associated with it in BCR while the decremental energy between Day-ahead schedule and Pmin is associated with a negative RT energy bid cost. The ISO proposes that the revenue rule remain in place for the range from the DA schedule and zero. The ISO proposes to refine the energy bid cost rule so that the real time bid cost calculation includes negative minimum load costs for the energy between Pmin and zero in addition to the RT energy bid cost between day-ahead and Pmin. In essence, this proposal aligns the decremental energy values used for the real time costs and revenues.

4. No change from the previous proposal: The performance metric (and the performance metric boundary as applicable), as defined in the previous section, will be applied to day-ahead and real-time minimum load costs.

5. New element of the proposal: The ISO will flag cases in which a resource persistently deviates from its real-time dispatch when it has been issued a shut-down instruction. A threshold will be applied and, if it is exceeded, minimum load costs for the flagged intervals will be excluded from the real-time bid cost recovery calculation.

With this current proposal, the ISO no longer anticipates a possible need to change the Expected Energy Allocation under the minimum load cost rules in this proposal.

As part of the current MSG Enhancements stakeholder policy initiative, there is a refinement to minimum load cost accounting for MSG resources that are dispatched but do not come within the tolerance band of the target configuration. That refinement is to provide minimum load costs for the next highest configuration for such cases, as opposed to disqualifying the MSG resource for all minimum load costs in those intervals.[21] This change to minimum load cost accounting for MSG resources is planned for implementation on a shorter timeline than the larger bid cost recovery changes proposed here. Implementation of this bid cost recovery proposal would make the enhancements to the MSG minimum load cost accounting moot. The reason for this is that the MSG enhancements change will use the minimum load costs for the next highest configuration if the resource does not meet the target configuration's minimum load (respecting the tolerance band). The instant proposal will make the tolerance band irrelevant because the performance metric will instead be used to scale minimum load costs based on the extent to which the resource follows the ISO dispatch to the target configuration. Note that this is a scaling of minimum load costs, and not of transition costs. In section 4.5 below, the treatment of start-up and transition costs will be described.

4.5 Proposed accounting of Start-Up Costs and Transition Costs

The proposal does not offer any changes with respect to start-up and transition costs.

Under this proposal, the treatment of start-up costs and transition costs will follow current practices with the exception of short-start resources as described in the following section.

The ISO proposes not to apply the performance metric to start-up or transition costs. In general, market participants and the Department of Market Monitoring agree that start-up and transition costs should be physically incurred in order to be counted as costs in the bid cost recovery calculation. Application of the performance metric is not consistent with this position because the performance metric is measured interval-by-interval. Start-ups and transitions are event-based, and the application of the performance metric to those costs is not appropriate.

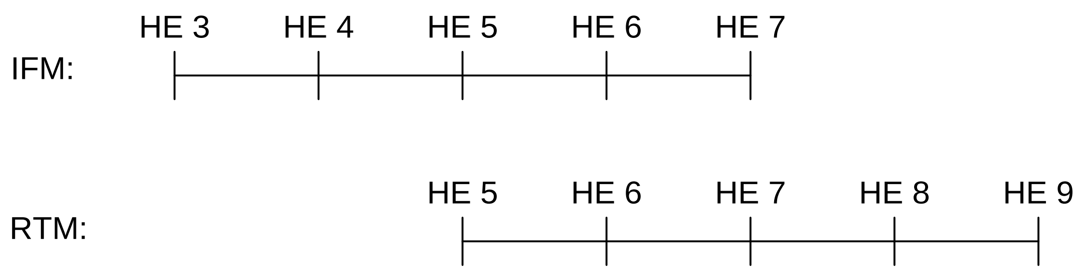
4.5.1 Start-up costs for short-start resources

For short-start units as currently defined in the Tariff, (i.e., resources that can be started-up by the real-time market), the same rules apply *except* for the following case: when the short-start unit is committed by the ISO in real time begins later than in the day-ahead ISO commitment *and* the two commitment periods overlap, the ISO will evaluate the qualification of start-up costs by comparing the meter to the real-time ISO commitment period. If the start-up is qualified, the start-up cost amount will be included in the day-ahead BCR calculation.

For example, consider the following scenario for a short-start unit:

[21] More information on the MSG Enhancements initiative is available at the following link: http://www.caiso.com/informed/Pages/StakeholderProcesses/Multi-StageGenerationEnhancements.aspx

Example of a short-start unit's IFM and RTM commitment



In this example, a short start resource is ISO-committed in the IFM for hours ending 3-7, and is subsequently committed by the ISO in the RTM for hours ending 5-9. If the resource's meter data show that it meets its Pmin at any point during hours ending 5-9, then its entire qualified start-up costs will be included as costs in the day-ahead BCR calculation.

For a short-start unit, the day-ahead optimization considers the resource's commitment costs when committed, and that commitment is financially (but not operationally) binding in day-ahead. The real-time market can again commit the short-start resource and the commitment instruction is operationally *and* financially binding in real-time. This is not the case for medium- and long-start resources; their day-ahead commitment instructions are operationally and financially binding because the resources do have to respond to the day-ahead commitment decisions to actually start-up according to the day-ahead schedules. The ISO recommends that the rules for extra-long start and long-start resource start-up costs remain unchanged from current market rules because the IFM commitment decisions are operationally binding for the long-start and extra-long start units and those units are expected to start-up based on the IFM decisions.

The intent of the overall BCR proposal is to separate the day ahead and real time bid cost recovery calculations and to thereby ensure that the day ahead and real time markets are individually made whole. The adaptation of the proposal for short-start units' costs is consistent with that intent. If a short-start unit is committed in the day-ahead and the real-time market makes use of that same commitment, then the start-up costs should be attributed to the initial commitment in the day-ahead market so the resource is made whole in the day-ahead if need be. It is logical to assign the start-up costs – as qualified by the metered output in real-time – to the day-ahead market rather than to the real-time market's commitment period in this case because the day-ahead market was the first of the two markets to make the commitment that was binding in both. In the current BCR calculations, there was no need to make a distinction for this delayed overlapping case because the day-ahead and real-time costs were ultimately all included in the same uplift calculation outcome.

4.6 Quantification of change to overall BCR uplift

The ISO has calculated estimates of bid cost recovery total values for 2010 under three scenarios:

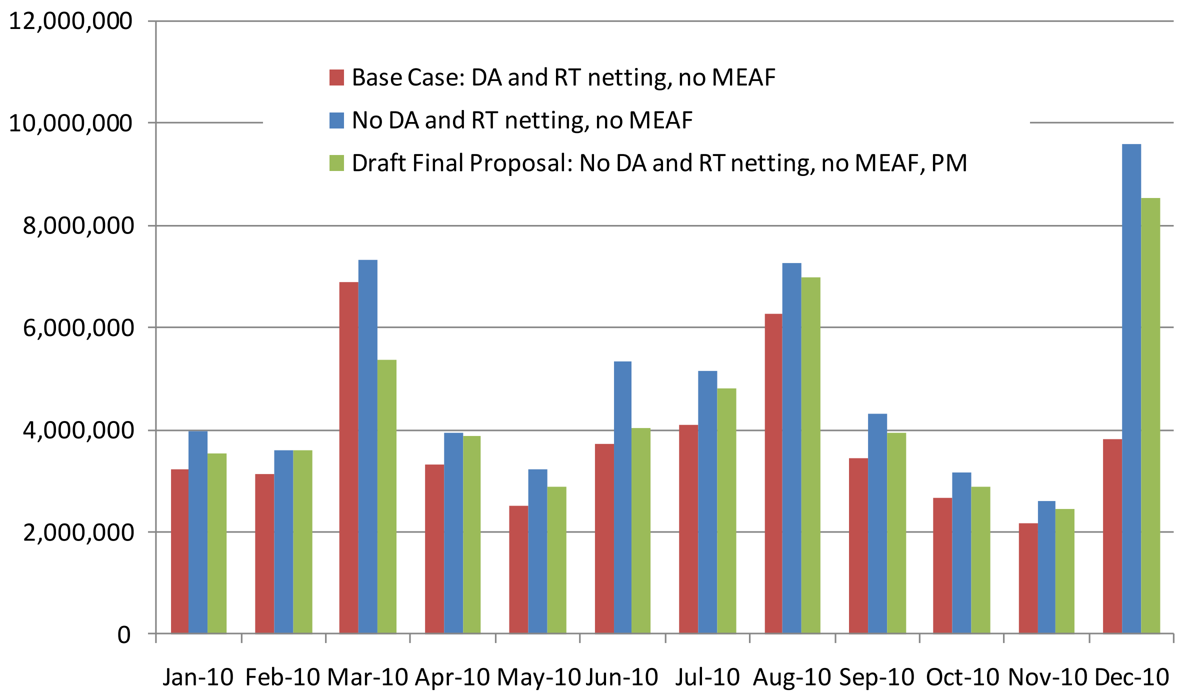
1. Day-ahead and real-time bid cost recovery calculations are netted together. The day-ahead metered energy adjustment factor is not applied. This case is essentially the "status quo."

2. Day-ahead bid cost recovery calculations are netted separately from the real-time bid cost recovery calculations. The day-ahead metered energy adjustment factor is not applied. This case is what the ISO presented in the fourth revised straw proposal for this initiative.
3. Day-ahead bid cost recovery calculations are netted separately from the real-time bid cost recovery calculations. The day-ahead metered energy adjustment factor is not applied. The performance metric is applied in both the day-ahead and real-time. This case is what the ISO is proposing in the draft final proposal for this initiative.

A few notes on this analysis:

- The calculations depicted in this chart are not based on running the full settlement system, but rather by coding these changes "by hand." They are estimates that are not necessarily coded with all the same intricacies and checks as settlements data are prepared.
- The analysis includes generating resources only. The values depicted below do not include cost recovery for intertie resources.
- There is no consideration of residual unit commitment payments considered in this analysis.
- The values in the chart below for December 2010 are anomalous due to the launch of MSG modeling functionality. During that time, there were significant deviations from real-time dispatch as participants and the ISO adapted to the MSG modeling functionality and its dispatch of MSG resources.

Figure 4.6(a): High-level quantification of BCR proposal



The chart depicts that bid cost recovery payments increase in aggregate when the day-ahead and real-time market surpluses and shortfalls are no longer netted together. It also shows that the performance metric dampens that effect by scaling back components of the day-ahead and real-time bid cost recovery calculations when resources deviate from the ISO dispatch.

These estimates do not reflect changes in behavior that will likely arise from the separation of the netting or the implementation of the performance metric. That said, in order to minimize the extent to which bid cost recovery payments could be scaled by the performance metric, resources will have the incentive to follow ISO dispatch instructions. Thus, one can logically predict a change in behavior such that the difference between the second and third scenarios (that is, without the performance metric and with it) will be smaller in magnitude than what we see in the historical analysis depicted above

4.7 March 25 and June 22, 2011 BCR filings

The ISO provides this discussion to assure stakeholders that the two BCR filings made earlier this year in response to adverse market behavior are confounded neither by separation of the BCR netting nor by not applying the DA MEAF. Brief background on those two filings is provided. Please refer to the filings themselves for detail.[22]

In the March 25 filing (docket ER11-3149), the ISO identified a bidding strategy that expanded bid cost recovery beyond competitive market outcomes. Specifically, resources were bid into the day-ahead market in a manner that forced the market to commit the resource at maximum capacity, and subsequently bid into the real-time market forcing the ISO to decrementally dispatch the resource to its minimum load. Because the metered energy adjustment factor[23] (MEAF) neared zero when the resource was decremented by the ISO in real time, an under-accounting of day-ahead market revenue was occurring. This in turn led to over-payment of bid cost recovery. In response to this market behavior, the ISO modified its bid cost recovery calculation to account for day-ahead market revenues based on scheduled (rather than delivered) energy for decremented resources. In short, the day ahead MEAF is no longer applied to day-ahead revenues when the ISO dispatches a resource downward from its ISO committed schedule in the day-ahead market.

Subsequent to the March 25 filing, the ISO observed a continuing bidding strategy causing multiple opportunities for the expansion of uplift associated with bid cost recovery and exceptional dispatch payments. This prompted the ISO to develop rule changes to remove the incentives for these complex strategies. The strategies and the rule changes are described in detail in the ISO's filing with FERC on June 22, 2011. FERC issued its order accepting the June 22 filing on August 19, 2011.[24] One element of these strategies was again related to the DA MEAF. Briefly, resources continued to supply negative bids to the day-ahead market while their minimum load costs were registered at 200% of their proxy costs. When those resources were dispatched down to or near their minimum load, again the day-ahead MEAF neared zero. The

22 The March 25 filing is available at the following link: http://www.caiso.com/Documents/March25_2011Errata-March18_2011TariffAmendment-ModifyMarketSettlementRulesinDocketNo_ER11-3149-000.pdf. The June 22, 2011 filing is available at the following link: http://www.caiso.com/Documents/June222011AmendmentremodBCRrulesexceptionaldispatchenergysettrulesdocketnoER11-3856-000.pdf

23 Information on the calculation of the MEAF is available in a Cost Recovery configuration guide associated with the ISO Settlements and Billing Business Practice Manual. The specific configuration guide is available at the following link: https://bpm.**caiso**.com/bpm/bpm/doc/000000000000536

24 http://www.caiso.com/Documents/2011-08-19_ER11-3856_BCR-ED_Order.pdf.

outcome of this was that the negative bids were not considered which resulted in an inconsistency with consideration of those bids in the commitment of the resource as well as in the over-accounting of bid costs. The market rule was changed so that the day ahead MEAF is no longer applied to negative bid costs.

To recap, the outcome of these two filings is that the day ahead MEAF is no longer applied either to day ahead bid costs when bids are negative or to day-ahead market revenues when the ISO dispatches the resource downward from its day-ahead ISO commitment. This is fundamentally because, in these two cases, the day-ahead MEAF nears zero which overstates costs and/or understates revenues and thereby artificially inflates bid cost recovery payments. Again, please refer to the filings themselves for additional details.

As discussed in section 4.3 above, the ISO proposes to do away with the application of the day-ahead MEAF altogether. This is already the case in those circumstances in which a resource is dispatched down from its day-ahead schedule, or in which the resource submits negative day-ahead bids.

The performance metric included in this revised proposal, although reminiscent of the MEAF, is based on real-time performance relative to dispatch and not relative to a day-ahead schedule. This is a key difference that is important to underscore here. There is not an incentive created to not follow the ISO's dispatch which is the case with the day-ahead MEAF under the circumstances described briefly above. In fact, under the performance metric, there is every incentive to follow the ISO dispatch as closely as possible.

5 Stakeholder comments on previous proposals

The ISO received many written comments throughout the stakeholder process. Those comments were valuable to ISO staff in further evaluating what had been proposed and as such the ISO significantly changed the RI-MPR Phase 1 proposal. For a complete review of all the stakeholders' comments, please visit the following webpage - http://www.caiso.com/informed/Pages/StakeholderProcesses/RenewablesIntegrationMarketProductReviewPhase1.aspx

Stakeholder	Comments	ISO Response
CalWEA	PIRP • Allocation of shortfalls to LSEs buying from PIRP resources is appropriate. • Existing PIRP resource should be allowed to stay in PIRP. • LSE consent should not be required for PIRP participation of new resources. • New resources should still be allowed to participate in PIRP if LSE consent is required but not given. • The total monthly PIRP shortfall amount should be aggregated across all plants scheduling in PIRP and allocated based on their volumes schedule across each	• Shortfall allocation – Allocating the shortfall on an aggregated basis provide a direct linkage to cost causation. LSEs with multiple PIRs will still maintain the pooling effect.

	month in PIRP. • There is no purpose in providing transparency through the proposed allocation methodology. • Supports suspending PIRP when prices are negative. Bid Floor • Support BCR Proposal • Supports proposal (stated in comments on the 4th revised straw proposal)	
Iberdrola	PIRP • Make no changes to PIRP. Address in RI-MPR Phase 2 • Changes to market design should grandfather existing long-term contracts. • Resource specific allocation negates any potential benefit from PIRP. Should be volumetric. Bid Floor • Supports (Comments on 4th Revised Straw)	• Grandfathering – The ISO continually refines elements of its tariff. Grandfathering defeats the purpose of trying to effect change in the markets. • Allocation concern – ISO's latest proposal provides the added benefit that pooling can be done outside of the ISO settlements if an SC would be interested in providing this service.
NRG	PIRP • Allocating PIRP costs to LSEs will detrimentally affect existing PPAs if the contracting LSE declines to accept those costs. Bid Floor • Does not support. Unclear that BCR changes will offset the negative effects of lowering the bid floor (Comments on 4th Revised Straw) BCR Proposal • NRG supports the CAISO's proposal to separate Day-Ahead and Real-Time Bid Cost Recovery, but does not know whether that proposal will be sufficient to offset the negative effects of lowering the bid floor. – from comments on 4th revised straw proposal	• PIRP – LSEs for existing PIRP resources can't decline to accept costs. For existing PIRP resources the ISO will get resource information from the LSE. Any disagreements will be handled on a case by case basis • Bid Floor - Lowering the bid floor is necessary to cover the opportunity costs of VER resources and incent economic dec bids.
Sempra Generation	PIRP • Proposal benefits CA consumers. (Comments on 4th Revised Straw) Bid Floor • The reduction in bid floor to -$300.MWh should be delayed to allow consideration of alternatives to enhance dispatch flexibility (Comments on 4th revised straw proposal) BCR Proposal	• Bid Floor – The ISO will file a tariff amendment with FERC to delay lowering the bid floor to -$300/MWh if it is warranted based on monitoring the markets outcomes with the bid floor at -$150/MWh. • BCR Proposal – The ISO has proposed the performance metric and the persistent UIE check instead of an uninstructed deviation penalty in order to finely scale BCR

	• The Proposal should provide greater support for use of the performance metric and the proposed parameters, as opposed to an uninstructed deviation penalty. • The Proposal should provide more detail on how the performance metric would be implemented.	when dispatch is not followed rather than applying a simple penalty. • The ISO has provided performance metric examples in excel spreadsheets which are posted to the website along with the 5th revised straw proposal.
Calpine	PIRP • No comment Bid Floor • Suggest that the ISO consider lowering the bid floor to -$75/MWh with additional reductions contingent on beneficial implementation of the downward flexible ramping product. (Comments on 4th Revised Straw)	• Bid Floor – See above
PG&E	PIRP • PIRP certification must be consensual. • No PPA – cannot qualify for PIRP Bid Floor • Supports DMM's comments on 4th revised straw proposal. • Second reduction should be considered only after analyzing a full year of data BCR Proposal • Supports separating day-ahead bid cost recovery (BCR) from real-time and residual unit commitment BCR. • RI-MPR Phase 1 BCR changes should be considered as part of the FERC-Ordered BCR stakeholder process. • The CAISO should implement all BCR changes, including changes resulting from the FERC-Ordered BCR stakeholder process, prior to lowering the energy bid floor. • Supports the concept of a BCR Performance Metric that adjusts recovery for both over- and under-delivery. • Supports the start-up cost rules for short start units.	• PIRP – For existing resources agreement between a resource and an LSE pre-exists, therefore consensual. For new PIRs the SC that is intended to be allocated the costs must provide consent. • Bid Floor – See above. • BCR Proposal – The ISO proposes that the performance metric and the persistent uninstructed energy check be implemented along with the separation of the netting because the effects of uninstructed deviations on BCR can be exacerbated when the markets are no longer netted together.
SCE	PIRP • Strongly opposes the current proposal. Recommends eliminating PIRP in the near future with minimal grandfathering. • Cost allocation proposal is an improvement over previous proposals.	• Dynamic Transfers – There was no good reason not to allow dynamic transfers as part of this initiative and would possibly be considered discriminatory to exclude them from this treatment, particularly since the SC that is allocated the costs will need to provide their

	• Strongly opposes PIRP for dynamic transfers • If proposal continues, ensure that PIRs are subject to all charges allocated to uninstructed deviations (referring to RUC charges) • Costs should be allocated directly to SC of the PIR not the LSE • Other ISOs do not have PIRP Bid Floor • Conditionally supports if (a) frequent administrative price spikes are observed the ISO will not lower the floor; (b) A study is conducted that demonstrates that a further reduction is needed. BCR Proposal • Believes that the significant complexity of the BCR process and of the new proposals require more stakeholder process. SCE does not support the current schedule. • Supports the spirit of the Performance Metric. Resources should be rewarded for following CAISO instruction and not guaranteed BCR for intervals where instructions are ignored. Also supports the proposed “boundary” to minimize the impact of small incremental dispatches. • Concerned that while the direction of the performance metric proposal appears reasonable, it is unclear how effective it will be in deterring inappropriate BCR. • Supports the new methodology proposed for allocating MLC for MSG resources between Day-Ahead and Real-Time.	consent. • BCR Proposal –The ISO has provided quantification of the magnitude of change between current BCR and BCR under the separation of the netting and with the implementation of the performance metric.
SDG&E	PIRP • Oppose current proposal. Does not address the need that was originally described. • Recommends that ISO should close PIRP to new entrants and phase out PIRP to existing participants (initial ISO straw proposal) (Comments on 4th Revised Straw) Bid Floor • Supported lowering to -$1000/MWh, but can support the current proposal (Comments on 4th Revised Straw)	• PIRP – An SC will have the ability to close PIRP to new entrants by not agreeing to the cost allocation for new resources.

Six Cities	PIRP • Support the cost allocation proposal but do not support extending PIRP indefinitely. Bid Floor • Lowering the bid floor to -$150/MWh is more than necessary and ISO should not lower to -$300/MWh until further evaluation of the overall effects are provided. BCR Proposal • Concerned that BCR awards under the proposed new calculation method may substantially exceed bid costs actually incurred by resources and impose excessive costs on loads. • Concerned that the revised BCR calculation methodology may result in unintended consequences or give rise to new gaming strategies at the expense of loads. • Suggest that the ISO modify the BCR proposal to incorporate limits on the BCR payments under the new calculation method by reference to the results that would occur under the current calculation method.	• PIRP – An SC will have the ability to close PIRP to new entrants by not agreeing to the cost allocation for new resources. • Bid Floor – The ISO will file a tariff amendment with FERC to delay lowering the bid floor to -$300/MWh if it is warranted based on monitoring the markets outcomes with the bid floor at -$150/MWh. • BCR Proposal – In concert with stakeholder feedback and input from DMM and the MSC, the ISO has evaluated possibilities for undue BCR, as well as for non-recovery of justifiable costs. The ISO is not considering capping BCR payments under the new design using the counter-factual of the current design.
SVP	PIRP • There is no discernable cost difference for an SC from an intermittent resource being in PIRP or not (Comments on 4th Revised Straw) • A small subset of grandfathered PIRP resources should receive unique cost allocation treatment due to their physical characteristics and historical operation dates. • Cost allocation should be volumetric, not resource specific • Also should give SCs the opportunity to look at 1 or 2 months of cost data so they can see how their allocations would change with the new cost allocation with resource specific vs. volumetric. Bid Floor • Concerned about potentially extreme prices when the bid floor goes to -$300/MWh (Comments on 4th Revised Straw) • Recommend that the ISO make limited cost data available to SCs	• PIRP – Creating a carve-out for older technologies and allowing their uplifts to be socialized to the market does not align with cost causation principles. • Cost allocation – The pooling of the allocation could be done outside of the ISO markets. • Cost data – This information should be available to stakeholders through their settlement information. • Bid Floor – The ISO will file a tariff amendment with FERC to delay lowering the bid floor to -$300/MWh if it is warranted based on monitoring the markets outcomes with the bid floor at -$150/MWh.

	for further analysis before lowering the bid floor beyond -$150/MWh.	
SMUD	PIRP • The ISO proposal "eviscerates" PIRP • The allocation proposal makes no sense, since the risk is not pooled. • Since PIRP is voluntary for a resource, it is not fair to make allocation mandatory for an LSE. • It is unacceptable to leave PIRP participants without a scheduling mechanism to cleanly limit exposure to negative pricing through some sort of curtailment mechanism until RI-MPR Phase 2 dec bidding implementation. Bid Floor • Understands the incentive mechanism, but should not be done without giving PIRs the tools to avoid these prices.	• Cost allocation – under the current proposal pooling of the costs could be performed outside of ISO settlements • Cost allocation is not mandatory – under the current proposal, new resources that want to be in PIRP must provide consent from the SC that will be allocated the costs. • Dec bidding – Participants can limit their exposure by bidding into the market rather than using PIRP when negative prices are expected. We will be initiating a stakeholder process in Spring 2012 to develop a dec bidding proposal for PIRP.
CPUC	PIRP • Concerned about the resource specific allocation of uplifts. • Allocation could add complexity to negotiated arrangements outside of the ISO • Unclear whether the ISO intends to encourage the use of centralized wind and solar forecasts for scheduling. Bid Floor • Requests that the ISO monitor and report impact of lowering the bid floor to -$150/MWh for a year. • Floor should be lowered if it is clearly warranted. BCR Proposal • CPUC Staff requests that the CAISO monitor and report market impacts and costs associated with the bid cost recovery (BCR) changes.	• Cost allocation – under the current proposal pooling of the costs could be performed outside of ISO settlements • Bid Floor – The ISO will file a tariff amendment with FERC to delay lowering the bid floor to -$300/MWh if it is warranted based on monitoring the markets outcomes with the bid floor at -$150/MWh. • BCR proposal – the ISO continually monitors bid cost recovery payments and the associated market behavior.
Powerex	PIRP • Did not comment. Bid Floor • Strongly supports symmetrical bid cap and floor. • If they are not symmetrical it could lead to unintended consequences • Support ISO's proposal as a first step.	
DMM	PIRP	• PIRP – The need for PIRP will be

	• Does not support the current proposal. • Recommend eliminating PIRP at the end of 2014 with limited grandfathering. (Comments on 4th Revised Straw) Bid Floor • Support lowering the bid floor to -$150/MWh but oppose automatically lowering it to -$300/MWh without subsequent study. (Comments on 4th Revised Straw)Bid Floor	re-evaluated in the future as new market enhancements are implemented. • Bid Floor – The ISO will file a tariff amendment with FERC to delay lowering the bid floor to -$300/MWh if it is warranted based on monitoring the markets outcomes with the bid floor at -$150/MWh.

6 Summary

Phase 1 of the Renewable Integration Market and Product Review consists of three elements.

- Update participating intermittent resource program (PIRP) cost allocation.
- The ISO will lower the bid floor from -$30/MWh to -$150/MWh in the first year and the -$300/MWh in the following year.
- Change the bid cost recovery netting methodology.

7 Next Steps

In July 2010, the ISO published a discussion paper which began the RI-MPR Phase 1 stakeholder process. This was followed by a succession of papers and presentations including an issue paper, a straw proposal, a revised straw proposal and a presentation regarding potential changes to PIRP.[25] Each step of the way stakeholders provided both verbal and written comments.[26] These informative and helpful comments that have been proposed during ISO's market design effort help to craft the current second revised straw proposal.

<u>Components and Schedule Objectives of Phase 1 Proposal</u>

Item	Date
Publish Phase 1 Draft Final Proposal	November 4, 2011
Stakeholder conference call	November 8, 2011
Stakeholder comments	November 18, 2011

25 Additionally there was a straw proposal, draft final proposal and revised draft final proposal devoted to Regulation Energy Management. All documents are available at the following link: http://www.caiso.com/27be/27beb7931d800.html

26 All stakeholder comments are available at the following link: http://www.caiso.com/27e3/27e3c4fbfbd0.html#2b5086745e5e0

Board of Governors Meeting – Phase 1	December 15-16, 2011

Please submit stakeholder comments by November 18th to RI-MPR@caiso.com.