California ISO

Shaping a Renewed Future

California ISO

Fifth Revised Straw Proposal

Renewable Integration: Market and Product Review

Phase 1

September 28, 2011

Fifth Revised Straw Proposal
Renewable Integration: Market and Product Review - Phase 1

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1 Introduction and Overview

The ISO started Phase 1 of the Renewable Integration – Market and Product Review, (RI-MPR) policy initiative 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 is comprised of two market design changes: (1) lower the energy bid floor to provide additional incentives for market participants, including variable energy resources (VER) to submit decremental (DEC) bids to enable the ISO to manage over-generation and congestion more efficiently and transparently and (2) evaluate options for wind and solar resources so that they participate more fully in our markets, in particular the real-time market. 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's prior proposals in this initiative have generated robust and extensive stakeholder discussion. This fifth revised straw proposal reflects the refinement of our previous proposals based on further analysis and consideration of stakeholder input and comment.

The specific proposals included herein are:

- <u>Update participating intermittent resource program (PIRP) eligibility requirements and cost allocation.</u> PIRP will be retained for existing PIRP resources and available to new participation. Uplift costs from PIRP will be allocated to load serving entities that have contracted with PIRP resources. For a new wind or solar resource to participate in PIRP they and their contracting load serving entity will need to provide a letter to the ISO confirming their desire to place the resource in PIRP. Once in PIRP, the uplift costs for that particular resource would then be allocated to the contracting load serving entity. Resources currently participating in PIRP will also need to provide the ISO information on their contracting LSE to enable the change in cost allocation discussed above.
- <u>Reduce the energy bid floor</u>. 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.
- <u>Change the bid cost recovery netting methodology.</u> 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 by resources in another market. The ISO recognizes that, without this change, it will 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 following table is a comparison of the last three Straw Proposals. Each proposal builds on the work of the previous version.

Element	3rd Revised Straw Proposal	4th Revised Straw Proposal	5th Revised Straw Proposal
PIRP	Grandfather existing participating intermittent resources and change the cost allocation. Close PIRP to new entrants.	Retain PIRP. Change PIRP cost allocation and eligibility requirements for new PIRP resources.	Same as 4th Revised Straw Proposal plus clarifying language
Energy Bid Floor	-$300/MWh	-$150/MWh – Year 1 -$300/MWh – Year 2	Same as 4th Revised Straw Proposal
Bid Cost Recovery	Separate day-ahead and real-time/RUC netting	Separate day-ahead and real-time/RUC netting	Same as 4th Revised Straw Proposal plus a performance metric mechanism and simplification of MSG minimum load cost accounting.

The proposals described in this paper will be discussed at a stakeholder conference call on October 5, 2011.

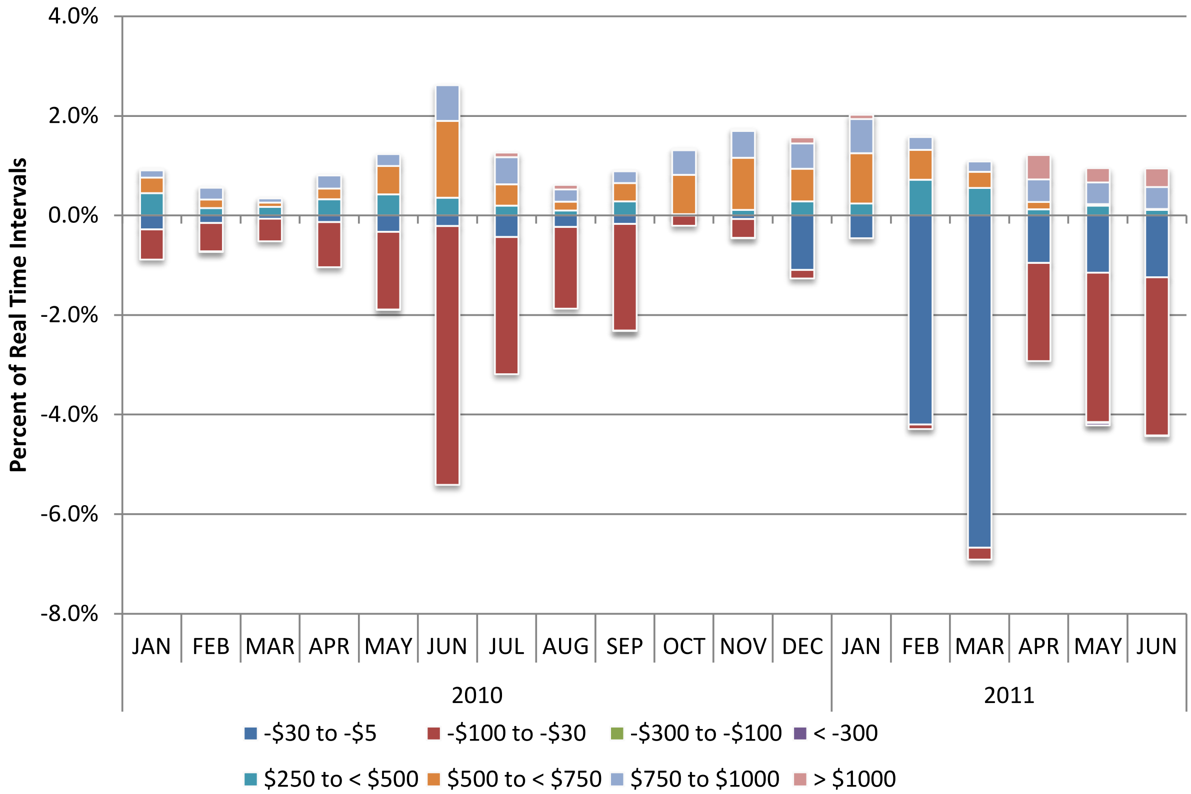
2 Participating Intermittent Resource Program (PIRP)

2.1 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.

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[2] 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 instructions 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

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

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.

2.2 Proposal

There are three proposed changes to the current PIRP program:

1. Uplift costs associated with PIRP will be allocated to LSEs that are contracted with PIRP resources instead of net negative uninstructed deviators;
2. Every PIRP resource must provide information regarding the LSE that will be allocated the uplift costs;
3. 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.

Other PIRP elements will remain unchanged at this time, although additional changes will be considered in RI-MPR Phase 2. 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).

<u>Eligibility requirements</u>

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.[3] 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 ISO will need certification to affirm the entity (or entities) that is contracted to buy the energy from the PIRP resource. This information will be used to ensure the proper allocation of the PIRP uplift costs. The PIRP resource and the LSE will jointly certify the following information:

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

- the PIR;
- the LSE and its scheduling coordinator;
- 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 of the LSE in the master file for settlements purposes.[4]

Based on the information provided, the ISO will update the master file to create a link between each PIR and the SC of the LSE. After the end of the month, the netted deviations for each PIR will be allocated to each SC of the LSE 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[5]. Among the notable parts of the dynamic transfer proposal are:

- 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

[4] Also, if the LSE consuming the PIR energy is also the owner of the resource, certification will entail that the generation is owned by the LSE and the SC for that LSE will be allocated the PIRP uplift costs.

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

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 the SC of the LSE buying PIRP energy in proportion to the contracted output of the resource in the Master File. If a PIR is bilaterally contracted with only one LSE, 100% of that resource's PIRP uplifts will be allocated to that LSE.

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 load serving entities that contract with PIRP resources. This approach means that scheduling coordinators for load without PIRs in their portfolio 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.

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.[6] 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.

2.3 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).

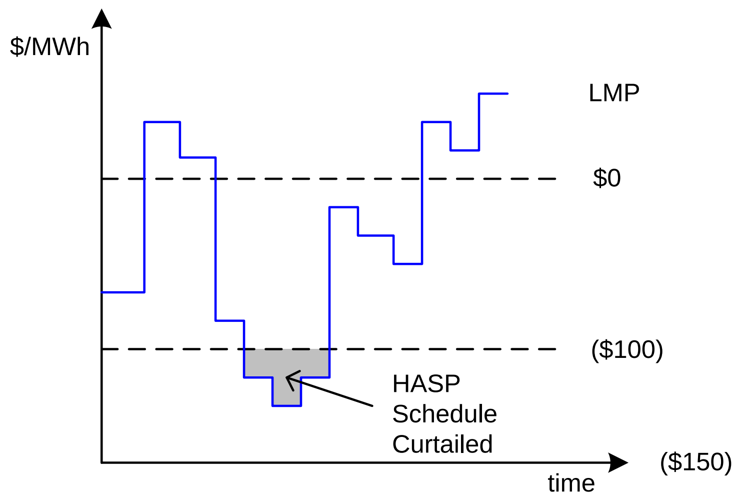
The ISO considered these proposals very carefully and determined that from an operational perspective this change could have a detrimental rather than beneficial impact to system reliability. Suspending PIRP during negative prices could indeed incent PIR resources to curtail, but it could also cause 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.

[6] 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 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 as a potential beneficial enhancement that could be implemented within the next few years. 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.[7]



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.

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

2.5 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 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

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.[8] 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.[9] 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 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.[10]

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.[11]

The ISO modified it 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 we propose to lower the floor to -$150/MWh initially and in the following year lower the floor again to reach -$300/MWh. 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,[12] is the primary federal incentive for wind energy and has been essential to the industry's growth.

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8 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.

9 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)

10 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.

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

12 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.

- 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.[13]
- 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 (and DMM) 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.

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 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. In other words, this may encourage generating resources to self-schedule in real time in order to protect a net shortfall in the DA. 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 RIMPR 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;

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

- 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 day-ahead and real-time costs or revenues 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.

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.[14] 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 has 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 RIMPR 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

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14 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

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 costs 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 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. However, in light of the need to ensure there are sufficient incentives to provide decremental bids in the real-time, the ISO now proposes to enhance its market rules to ensure the requirement is met given the ISO's changing fleet of resources with the influx of VERs over time. To achieve the targeted incentives, the ISO proposes to split the netting between the DA and RUC/RT markets.

In the previous iteration of this proposal, the ISO asserted that the logic of separating the BCR netting is inconsistent with the pro-rating day-ahead costs based on performance in the RT. However, in this fifth revised straw proposal, the ISO is refining its recommendation due to internal analyses and stakeholder feedback, including feedback from the Department of Market Monitoring. The ISO recognizes that there can be adverse incentives created by eliminating entirely the impact of real-time performance. Nonetheless, the ISO maintains its proposal to eliminate the day-ahead MEAF – which is based on the portion of *day-ahead scheduled energy* that is actually metered. In place of the day-ahead and real-time MEAF, the ISO proposes a performance metric that considers instead the ratio of metered and *dispatched* energy. Specifically, the ISO is proposing that the performance metric be calculated per resource and per settlement interval in the following manner:

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

1. Bid costs and revenues are both positive: apply PM to costs, but not to the positive revenues;
2. Bid costs are positive, revenues are negative: apply PM to negative revenues (which are, in effect, costs) and to bid costs;
3. Bid costs are negative, revenues are positive: irrelevant case; and
4. Bid costs and revenue are both negative: apply to negative revenue (which are essentially costs) and not to negative costs (which is essentially revenue).

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.

$$\sim if \sim$$

$$|Metered\ Energy - Regulation\ Energy - Total\ Expected\ Energy| \leq 5/6\ MWh$$

$$\sim or \sim$$

$$Performance\ Metric\ \leq 3\%$$

$$\sim then \sim$$

$$Performance\ Metric\ is\ not\ Applied$$

With this change, **net costs** or **net revenues** will be reduced to the extent measured by the performance metric. Note that this applies to over-delivery as well as under-delivery relative to ISO dispatch; it also applies to both the day-ahead and real-time markets.

This performance metric is not a methodology employed by other ISOs. Benchmarking against those ISOs has shown that they all have implemented uninstructed deviation penalties to provide a disincentive to deviate from real-time dispatch.

4.4 Proposed accounting of Energy Bid Costs and Minimum Load Costs

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

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

2. <u>No change from previous proposal</u>: 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. <u>New element of the proposal</u>: 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.

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

1. <u>No change from previous proposal</u>: 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. <u>New element of the proposal</u>: 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,

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

   The fourth revised straw proposal included a more elaborate proposal with respect to minimum load costs for MSG resources with different day-ahead and real-time configuration. The four scenarios[15] provided in the previous proposal illustrated how the

15 The four cases were for both incremental and decremental dispatches and for non-over lapping and over-lapping configurations.

ISO recommended real-time minimum load costs be calculated such that only the proportion of a configuration's MLC that is incurred by moving from the DA configuration to the RT configuration is attributed to RT for the purpose of the BCR calculation. Stakeholder feedback, however, brought up the concern that in these scenarios there could be instances in which an MSG would not be made whole for all incurred minimum load costs.

With the inclusion of this third 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 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 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; and

4. New element of the 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.

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.[16] 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

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

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.

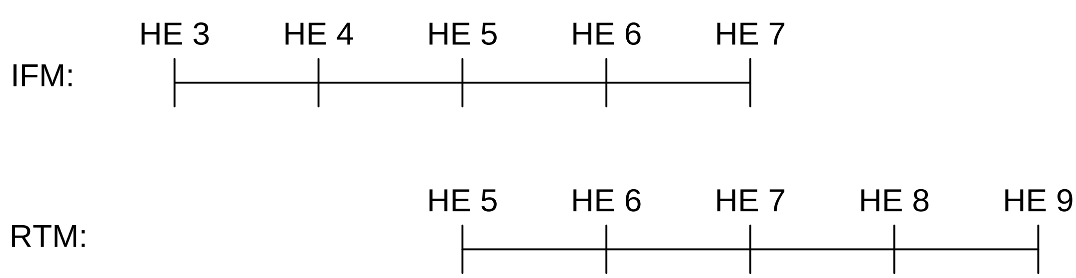
The ISO proposes not to apply the performance metric to start-up or transition costs. In general, market participants and the Department of Market Monitoring agree that start-up and transition costs should be physically incurred in order to be counted as costs in the bid cost recovery calculation. Application 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:

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 is continuing to assess the expected increase in bid cost recovery uplift payments when day-ahead costs and revenues are netted separately from real-time and residual unit commitment costs and revenues.

A detailed analysis of ten months of data (from April through December 2010) on bid cost recovery found that removing the netting between the day-ahead market, and the RUC and real-time markets, and eliminating the application of the day-ahead MEAF led to an increase in total BCR payments of 14%. These calculations assume that no MEAF was applied in the day-ahead for this entire period. However, the analysis does not factor in the application of the Performance Metric proposed in this revised straw proposal. Application of the performance metric will reduce overall BCR payments since the metric scales BCR based on the extent to which the resource follows dispatch instructions. Thus, a 14% increase is the upper bound for the increase to BCR using this historical analysis.

The ISO is extending this analysis to include the application of the proposed performance metric, and is striving to have that completed for stakeholder consideration as soon as possible.

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.[17]

[17] 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

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[18] (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.[19] 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 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 <u>not</u> 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.

18 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

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

5 Stakeholder comments on previous proposals

The ISO received 13 sets of stakeholder comments on the 3rd revised straw proposal. 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	Response
8minutenergy	Strongly support including dynamic transfers in the PIRP proposal	
Brookfield	Do not change any features of PIRP, including cost allocation. Wait for RI-MPR Phase 2.	The cost allocation change is appropriate. It only allocates PIRP costs to LSEs that have contracts with PIRs.
	Not opposed to the step down approach to lowering the energy bid floor. Need specifics about how to progress from the first step to the second step.	The ISO (and DMM) 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.
	Support the proposal to modify bid cost recovery.	
Calpine	Suggests that the ISO consider lowering the bid floor to -$75/MWh with additional reductions conditioned upon beneficial implementation of the downward flexible ramping product described in RI-MPR Phase 2.	-$75/MWh does not provide sufficient incentives for wind and/or solar resources to curtail in the event of over generation conditions.
	Agrees with the intent of BCR reform. Supports the elimination of DA MEAF.	
	Supports hourly BCR in real-time.	Hourly BCR is not compatible with the current optimization time horizon.
CalWEA	Oppose proposed "default" PIRP cost allocation to generators; neutral position on allocating "shortfall' costs to LSEs if a broad based allocation method is not used.	Section 2.2 clarifies that cost allocation will be assigned to an LSE; it will not default to the generator.

	Oppose PIRP cost allocation based on plant-specific shortfall – ISO should allocate shortfalls proportionally to energy scheduled in PIRP.	The cost allocation proposal is meant to increase visibility of resource costs and more closely align with cost causation principles
	Generally agree to continue PIRP in the future but participation should not be conditioned on LSE agreement to absorb shortfall	A resource must have an LSE identified for the allocation of uplift charges.
	Support expanding PIRP eligibility to dynamic transfer resources.	
	Support suspending PIRP when prices are negative.	See Section 2.3 for details regarding this proposal.
	Support the energy bid floor proposal	
	Support the BCR modifications.	
CEERT	Cost allocation should be applied broadly across those receiving the benefit of VERs. Concerned that a PIR without a bi-lateral contract with an LSE will have the uplift charges allocated back to itself.	A resource must have an LSE identified for the allocation of uplift charges.
	ISO should consider suspending PIRP under negative pricing events.	See Section 2.3 for details regarding this proposal.
CPUC	Supports more gradual lowering of the bid floor to start with -$150/MWh	
	Supports separate revenue-cost netting in the day-ahead versus real time markets for BCR.	
	Supports the continuation of PIRP	
	Wants clarification that resources can opt out of PIRP on an hourly basis.	Yes, this is true. If a resource that is certified as a PIR schedules in alignment with the forecast provided by the ISO for that hour they are eligible for the PIRP netting treatment. They are not required to do this. If they do not schedule the forecast, but do something else they are

		"opting out" of PIRP for the period of time in which their schedule is different from the forecast.
	CPUC proposed a pro-rata approach to cost allocation.	The ISO analyzed this proposal and found that this formula does not seem to allocate the costs properly in many cases.
DMM	Support lowering the bid floor to -$150/MWh but have concerns about automatically lowering it to -$300/MWh without subsequent study.	If issues arise that are cause for concern, the ISO will re-evaluate its proposal to step down to -$300/MWh.
	Generally supports bid cost recovery changes	
	Recommends eliminating PIRP at the end of 2014 with limited grandfathering (2nd revised straw proposal). Does not support the current proposal.	The need for PIRP will be reevaluated as new market enhancements are implemented in the future.
Iberdrola	Supports the energy bid floor proposal	
	ISO should allocate PIRP shortfalls to the LSE not the PIR.	
	Concerned that the PIRP revenue shortfall is allocated directly based on its deviation amount. Should consider a volumetric allocation.	The cost allocation proposal is meant to more closely align with cost causation principles.
Modesto Irrigation District	Concerned about the reassignment of costs to the SC of the LSE by presenting a bilateral contract. Without any scheduling or meter data, the LSE's SC would have no way to verify any PIRP charges which may be allocated.	The ISO settlement statement to the LSE will provide these costs based on resource ID.
	Concerned that if a generator owner is acting as an SC for a contracted LSE, the LSE does not have any choice as to the participation of the VER in PIRP and would have no avenue to offset the charges.	The LSE and the VER need to agree to the allocation of these charges.

NRG Energy, Inc.	It is unclear that separating day-ahead and real-time BCR will offset the effects of lowering the bid floor. Does not support the energy bid floor changes.	The separation of netting reduces exposure of day-ahead shortfalls to offsetting real-time revenues which removes a disincentive to submitting real-time economic bids. Lowering the bid floor is necessary to cover the opportunity costs of VER resources and incent economic dec bids.
	Supports separating day ahead and real-time bid cost recovery changes.	
	ISO's proposal could disadvantage both resources that have existing PPAs and resources that retain SC responsibilities.	Based on discussions with market participants, it is the ISOs understanding that the vast majority (if not all) of the PIRs are under contracts to LSEs that convey the costs and benefits of PIRP to the LSE. It is further the ISO's understanding that the vast majority (if not all) of the PIRs have contracted with an LSE to serve as the SC for the resource. While the ISO understands that the issue raised here is theoretically possible, it is not true in practice. Further, once the new rules are established, future contracts should consider the market structure and therefore be unaffected.
PG&E	Support the PIRP proposal with the additional certification requirement. Intermittent resources without a PPA with an LSE should not qualify for PIRP	
	Need clarification on how PIRP will work with dynamic transfers.	See section 2.2 for additional details.
	Recommend formal DMM review before lowering the bid floor beyond -$150/MWh	
	BCR should be rolled into a larger BCR stakeholder process	The scope of this initiative is limited to separating the netting between the day-ahead and real-time markets. The ISO will hold a subsequent stakeholder process to address any further BCR issues.
	Reduction in energy bid floor should be implemented coincident with changes to	

	BCR.	
Powerex	Support a symmetrical bid cap and floor. The ISO's proposal does not adequately address other unintended consequences of an asymmetrical methodology.	When the bid floor is lowered, there is a greater possibility of increased dec bidding. This should reduce the amount uneconomic curtailments.
	Recommends that real time bid cost recovery be netted by individual hour rather than over the entire day.	This is not within the scope of the current proposal.
SCE	Strongly opposes the current PIRP proposal. Recommends that the ISO eliminate PIRP in the near future with minimal grandfathering.	The need for PIRP will be reevaluated as new market enhancements are implemented in the future.
	Conditionally supports the energy bid floor proposal dependent on the ISO commitment not to lower the floor if frequent, administrative price spikes are observed.	
	Does not support the current schedule for bid cost recovery because of the significant complexity of the topic.	The scope of this initiative is limited to separating the netting between the day-ahead and real-time markets. The ISO will hold a subsequent stakeholder process to address any further BCR issues.
SDG&E	Very disappointed in the PIRP proposal because it does not provide the incentive for more economic bidding.	The need for PIRP will be reevaluated as new market enhancements are implemented in the future.
	Recommends that PIRP uplifts be allocated to the SC of the VER rather than the LSE.	The ISO's proposal does not consider allocation to the SC of the VER since they would be allocated the same costs that they are being paid, providing no benefit.
	Can support the ISO's current energy bid floor proposal.	
	Supports the ISO's bid cost recovery proposal.	
Sempra Generation	Supports the ISO's PIRP proposal.	
	Supports allowing dynamic	

	transfers to participate in PIRP.	
	The ISO should evaluate the effectiveness of lowering the bid floor to -$150/MWh before lowering it further.	
	Supports the ISO's BCR proposal.	
Six Cities	Supports the ISO's PIRP allocation proposal but does not support allowing PIRP to continue indefinitely.	The need for PIRP will be reevaluated as new market enhancements are implemented in the future.
	Moving the bid floor down to -$150/MWh is more than is necessary, but it is acceptable as an initial step. The impact should be evaluated before further changes.	
	The proposed BCR methodology may substantially increase BCR payments and could increase potential gaming strategies	The ISO has performed an analysis of the expected increase to BCR payments. See section 4.6. DMM has been involved in the development of this proposal to help identify and mitigate for potential gaming strategies.
SMUD	Supports the energy bid floor proposal.	
	Recommends the "Positive PIRP" approach	See Section 2.3 of this proposal for information regarding this approach.
SWP	Recommends including two-tier real-time market bid cost recovery in the RI-MPR Phase 1 proposal.	That is outside of the scope of the RI-MPR 1 proposal.
SVP	Concerned about potentially extreme prices when the bid floor goes to -$300/MWh.	
	There is no discernable cost difference for an SC from an intermittent resource being in PIRP or not.	Much of the benefit of PIRP lies with the resource although the RI-MPR Phase 1 proposal provides additional transparency to the SC of the costs of each PIR.
	Recommends the ISO make limited cost data available to SCs for further analysis.	

6 Summary

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

- Update participating intermittent resource program (PIRP) eligibility requirements and 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.[20] Each step of the way stakeholders provided both verbal and written comments.[21] These informative and helpful comments that have been proposed during ISO's market design effort help to craft the current second revised straw proposal.

Components and Schedule Objectives of Phase 1 Proposal

Item	Date
Publish Phase 1 Fifth Revised Straw Proposal	September 28, 2011
MSC Meeting	September 30, 2011
Stakeholder conference call	October 5, 2011
Stakeholder comments due	October 12, 2011
Publish Phase 1 Draft Final Proposal	November 1, 2011
Stakeholder conference call	November 8, 2011
Stakeholder comments	November 15, 2011
Board of Governors Meeting – Phase 1	December 15-16, 2011

[20] 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

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