Updated Catalogue of Market Design Initiatives – RED LINE

July, 2009

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Prepared by

Market and Infrastructure Development

Catalogue of Market Design Initiatives

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Catalogue of Market Initiatives

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1. Introduction

The origins of this catalogue can be found in the 2008 Catalogue of Market Initiatives, the "Market Initiatives Roadmap Process Final Report on High Priority Market Initiatives, 7/7/2008"[1], and the preliminary 2009 Market Design Initiatives Catalogue that was publish on June 12th of this year. The information contained in those documents has been used to compile this updated catalogue of market design initiatives. In 2008, the ISO staff refined the 2007 market design roadmap process, and this year some additional refinements have been introduced.

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The catalogue has been reorganized to reflect the various markets and products that are currently relevant to the ISO. Last year the structure of the catalogue reflected the impending implementation of the Market Design and Technology Upgrade (MRTU). The sections reflected how the initiatives related to the launch of the new market – whether pre-MRTU, within 12 months of launch, future market releases, etc. Now that the ISO has successfully moved beyond that milestone, the document has been revised to reflect the new market environment.

Additionally, the scope of the catalogue has been reconsidered. This year the focus is solely on market design initiatives. "Market design" can be described to include policy changes and enhancements rather than process improvements or administrative type changes. In the past, the catalogue contained some topics that while important and timely to stakeholders and staff, were not necessarily related to market design. The purpose of the revisions to the catalogue and ranking process is to evaluate potential changes to existing market design policy enhancements while keeping process and finance related initiatives separate. Hence, we have removed initiatives related to grid management charges, payment acceleration and credit limits

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This document contains the issues and market design initiatives identified by stakeholders and staff in the 2008 Roadmap process as well as some new initiatives that have been identified since the last posting of this document. Some of the new initiatives that have been added are not fully scoped or developed, but rather were based on market experience since June 2009 or suggested by stakeholders in the past year. Examples of these include A/S maximum limits for spin and non-spin, ramping capacity product, allocation of intertie capacity, revised load migration process, enhancements to the standard RA capacity product and rules to encourage dispatchability of wind and solar resources.

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The first 4 sections after this introduction (sections 2 through 5) describe initiatives related to the various ISO markets (day ahead, hour ahead, real time and residual unit commitment). This is followed by sections 6 and 7 related to certain categories of products (ancillary services and congestion revenue rights). The next two sections describe initiatives related to regional topics (resource adequacy and seams issues). Section 10 contains the miscellaneous market design initiatives that do not clearly fall into any of the other sections. Finally, the catalogue concludes with a Section 11 which holds the 22 market design initiatives that have been completed and another 18 that have been deleted. As explained above, some initiatives were deleted due to refining the scope of the catalogue. Others were deleted because they reflected broader strategic objectives rather than specific design initiatives. One example of this is "Renewable

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[1] These documents are posted on the ISO website at http://caiso.com/1fb1/1fb1856366d60.html

Integration". Rather than identify this as a specific project, we have instead identified several initiatives within the catalogue that help the ISO reach this goal. However, there remains an Integration of Renewable Resources Program (IRRP) within the ISO that will potentially generate market design relevant projects over time.

Consistent with the 2008 catalogue, each initiative has been identified with a letter code signifying the status of the initiative. These codes are found next to the title of each item. The key to the codes are as follows:

D - Discretionary or "rankable" Items

F - FERC Mandated Items

I - In-Progress/Planned Items

N - Non Discretionary Items

As a convenience these designations are also listed on the footer of each page.

Additional information regarding the ISO Roadmap process can be found on the ISO website at:

http://www.caiso.com/1fb1/1fb1856366d60.html

1.1 Stakeholder Comments on June 12, 2009 Catalogue of Market Design Initiatives

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The ISO requested stakeholder comments on the initial 2009 version of this catalogue. Specifically, we were looking for stakeholders to let us know if the catalogue was complete and correct. Eleven sets of comments were submitted. The following table summarizes each parties' comments and the ISO's resulting actions.

Commenter	Summary of Comments	ISO Action
California Department of Water Resources (CDWR)	1) Participating Load Refinements should be implemented concurrently with Proxy Demand Response 2) Supports the re-review of Multiple SCs at a Single Meter 3) Hourly AS Contingency Designation – why wasn't this discussed at the release plan meeting? 4) Supports the Spin/ Non-Spin Max Capability Operating Limits 5) Suggestions for improving catalogue design	1) This comment will be forwarded to the implementation team for review. 2) Multiple SCs at a Single Meter remains in the catalogue and has been reviewed for 2009 ranking. 3) There are factors in addition to the Market Initiatives Roadmap ranking that impact the implementation of any given item such as coordination with non-discretionary items, system impacts, etc. 4) Noted.

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		5) Some good suggestions, however some items, such as the Gantt chart of critical dates, go beyond the scope of the catalogue.
California Wind Energy Association (CalWEA), Large-scale Solar Association (LSA), American Wind Energy Association (AWEA)	Suggestions concerning Section 4.1 – Rules to encourage dispatchability of wind and solar resources. - Change PIRP rules - Lower current $-30 dec bid floor	These suggestions are noted in the catalogue.
Dynegy	1) Voltage Support Procurement and Black Start Procurement are listed as discretionary but should be labeled "F" for FERC Mandated 2) Efforts that are listed with a "D" or an "I" and the ISO has committed to doing should contain an estimate of a proposed schedule for implementation 3) Need to include an initiative that will determine the successor to ICPM	1) The ISO has been ordered by FERC to look into the need and feasibility of these products, but did not comment on timing. The timing is still subject to debate which is why these have been labeled as "D". 2) The catalogue is a reference guide to the market design initiatives, the implementation (or release plan) stakeholder process identifies the implementation schedule for these initiatives. 3) This has been added to the catalogue.
EPIC Merchant Energy	- Convergence Bidding should be a FERC Mandated Enhancement - Convergence Bidding is not an initiative that is in progress	The ISO agrees that Convergence Bidding is a FERC Mandated Enhancement and this is noted in this updated catalogue. The ISO disagrees with EPIC's characterization

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		of the current Convergence Bidding market design process.
Joint Comments of Sacramento Municipal Utility District (SMUD), Transmission Agency of Northern California (TANC), the Modesto Irrigation District (MID) and the Turlock Irrigation District (TID)	The ISO's status of IBAA is "substantially incomplete, and therefore inaccurate portrayal"	Comments have been forwarded to the internal team associated with this effort for further review.
NRG Energy	1) Enhancements to SCP – description should include the fact that FERC ordered the ISO to work with stakeholders on sunset date for deferrals. NRG also suggests that this initiative should address current RA MOO exemptions 2) Comments on Section 7 Reliability Products related to the February 20, 2009 FERC Order. 3) Supports market products to address operational needs and reliability requirements related to exceptional dispatch status report.	1) The description of SCP Enhancements has been updated to include these items. The priority of this initiative will be determined in the ranking process (followed by the corporate strategic initiative process) and timelines will follow. This information is not available in the catalogue but in the release plan process. 2) Section 7 has been incorporated into section 6 (Ancillary Services) in this version of the catalogue. See response to Dynegy comments above 3) The ISO is continuing to analyze the exceptional dispatch issue. Once the analysis is complete, a stakeholder process will commence, if warranted.
Pacific Gas & Electric (PG&E)	1) Each initiative description should include the scope of the problem and an	1) Appreciate the suggestion. The Market Design

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	assessment of potential solutions 2) New initiatives suggested: a. Pumped Storage Generation Plant Modeling b. Delivery of Intermittent Power from Out of State c. Enhanced Inter-Scheduling Coordinator Trade (IST) Functionality for Contract Settlements 3) Clarification of the following: a. More comprehensive definition of "market design" b. Additional detail regarding the determination to "dispose" of items in the catalogue c. Add more consistency to the terminology used throughout d. Addition of a Gantt chart for the implementation of identified market initiatives	Initiatives team strives to provide as much information as possible in a condensed fashion. It is a work in progress and we continue to refine the descriptions 2) New Initiatives a. This has been added to the catalogue. b. This is part of the Dynamic Scheduling effort. c. This requires more information from PG&E on specific enhancements before a determination can be made. 3) Clarifications: a. The introductory section of this paper has been updated with more information related a market design definition b. Each initiative that has been deleted has an explanation listed in the "status" section c. Agreed. This version of the catalogue has been corrected to reflect the correct designations. d. Implementation plans are the purview of the release planning team and are not part of the scope of

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		this catalogue.
RRI Energy	- Transmission outage information should be published as soon as it is available - The ISO should expand it publication of information on constraints and contingencies	This request appears to be outside of the scope of the Market Design Initiative catalogue; however, the ISO has initiated a comprehensive internal effort regarding its information release policy. A stakeholder process is scheduled to begin later this summer.
Sempra Energy Solutions, LLC (SES)	SES proposes adding "Development of a Comprehensive Public Web Portal" to the market design catalogue.	This initiative is an enhancement that is not directly related to market design. It has been referred to the ISO's Information Products & Services department for further evaluation.
Southern California Edison (SCE)	1) Instead of asking stakeholders to prioritize issues from a broad range of categories, the roadmap process should revolve around the ISO's major market objectives. 2) A section should be added "Near Term Real-Time Market Enhancements" and should include (but not limited to): a. Improvements in RT constraint modeling b. Improving the process for constraint relaxation c. RT Price formulation d. Dispatch of RT AS e. Better shut-down modeling of generation 3) Add a section for development of a capacity	1) The ISO's major market initiatives are considered during the corporate strategic planning process. The results of the ranking process inform that planning process. 2) The market design initiatives catalogue is designed to capture forward-looking market design enhancements. Most of the near term real-time market enhancements are handled by the implementation/release planning team. These suggestions will be forwarded to that group. 3) A section has been added to reflect that a replacement for ICPM must be developed.

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	market 4) Request clarification on: a. A/S maximum capability operating limits for spin and non-spin b. Interchange transactions after the RT market.	4) Clarification a. A/S Maximum Capability Operating Limits for Spin and Non-Spin are separate from the MSG Initiative. b. The IST request fall is a separate item. The interchange scheduling issue has to do with allowing SCs to schedule over intertie capacity that is not fully loaded after the HASP. In contrast the IST issue is simply a financial transaction that would be decided based on different criteria.
Western Area Power Administration – Sierra Nevada Region (WAPA)	1) "Improve Tagging Procedures and Functionality" should remain active in the catalogue 2) Disagrees with our status on IBAA 3) Add the following items: a) Rollover DA Awards for ETC, TOR and/or Wheels to RTM b) Ability to change TRTC and Master File Instructions Hourly c) CRN API Data d) True Trading Hub e) AS Procurement in HASP	1) The tagging procedures are handled outside of the scope of the market design process WAPA's comments related to tagging will be forwarded to the Scheduling team. 2) See response to Joint Parties Comments 3) Additions: a. This is a software gap and not a market design issue. The software design team is aware of this issue. b. See a. c. See a. d. This is being handled

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within the convergence bidding design effort.

e. This effort is in progress. The market design team will be publishing a paper regarding this issue.

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1.2 The Market Design Initiative Ranking Process

Each year the ISO and stakeholders review and perform an evaluation on the market design initiatives contained in the catalogue. The ranking process that was used in 2008 will be used once again to prioritize the initiatives included in this document. Figure B describes this process flow. The ranking process involves two steps:

High Level Prioritization

The CAISO will first conduct a high level assessment of proposed market initiatives in the Market Design Initiatives Catalogue by applying a simplified ranking process of three benefit and two feasibility criteria based on stakeholder input. In this iteration of the ranking process, each initiative will be graded "High", "Medium" or "Low" based on the results of their criteria ranking. The high level benefit criteria are "Grid Reliability", "Improving Market Efficiency", and "Desired by Stakeholders" as shown in Figure A below. The high level feasibility criteria utilize two measures: "Market Participant Implementation Impact" and "CAISO Implementation impact".

Figure A - CAISO HIGH LEVEL PRIORITIZATION CRITERIA

#		Criteria	HIGH	MEDIUM	LOW	NONE
			10	7	3	0
1	Benefit	Grid Reliability	Significant Improvement	Moderate Improvement	Minimal Improvement	No Improvement
2	Benefit	Improving Overall Market Efficiency	Significant improvement	Moderate improvement	Minimal improvement	No impact
3	Benefit	Desired by Stakeholders	Universally desired by stakeholders	Desired by majority of stakeholders	Desired by a small subset of stakeholders	No apparent desire
4	Feasibility	Market Participant Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact
5	Feasibility	ISO Implementation Impact ($ and resources)	No Impact	Minimal Impact	Moderate Impact	Significant impact

Detailed Ranking

After determining the results of the high level prioritization the selected initiatives are ranked again using more detailed criteria based on stakeholder input. Each of these criteria has a weight associated with it, based on its relative importance. The weighting is a scale from 1 to 10 with 10 being the highest weight. For example, "Grid Reliability" is assigned a weight of 10 because it is a core function of the CAISO while "Process Improvement", an important but not critical criterion, is ranked substantially lower at 5. Those proposed market initiatives that are ranked highest will be considered in the Corporate Strategic Planning Process.

The following schedule is planned for the 2009 Market Design Initiative Roadmap Process:

Deleted: Appendix A contains the detailed ranking results from last year.¶

July

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<#>6/12 – Publish 1st Draft of 2009 Market Design Initiatives Catalogue ¶
<#>6/19 – Stakeholder Conference call on Roadmap Process¶
<#>6/26 – Stakeholder Comments due on content and correctness of catalogue¶

- 7/13 - Publish Revised 2009 Market Design Initiatives Catalogue
- 7/13 – Publish results of high level ranking
- 7/23 – Stakeholder meeting on high level ranking
- 7/30 – Stakeholder comments due on results of high level ranking

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August
- 8/10– Publish straw proposal for high priority enhancements
- 8/17 – Stakeholder Conference Call regarding high priority enhancements
- 8/24 – Stakeholder comments due on straw proposal

September
- 9/9– Publish Draft Final proposal
- 9/16 – Stakeholder conference call to review Draft Final proposal

Fourth Quarter
- Internal process to coordinate results of Draft Final Proposal and High Priority Enhancements with Corporate Strategic Planning Process

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1.3 Strategic Planning Process

The 2009 Strategic Plan Update includes Corporate Initiative 2.2 -- "Develop Well Functioning and Transparent Electricity Markets" -- which focuses, among other things, on implementing value-added market design enhancements after the start up of the new market.[2] The market design initiative catalogue and roadmap process are essential to this effort. Once the Draft Final Proposal and the ranking process are complete, the ISO will incorporate the results in the updated Five Year Strategic Plan for 2010 (planning horizon 2010 – 2014).

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1.4 Markets and Performance (MAP) Releases

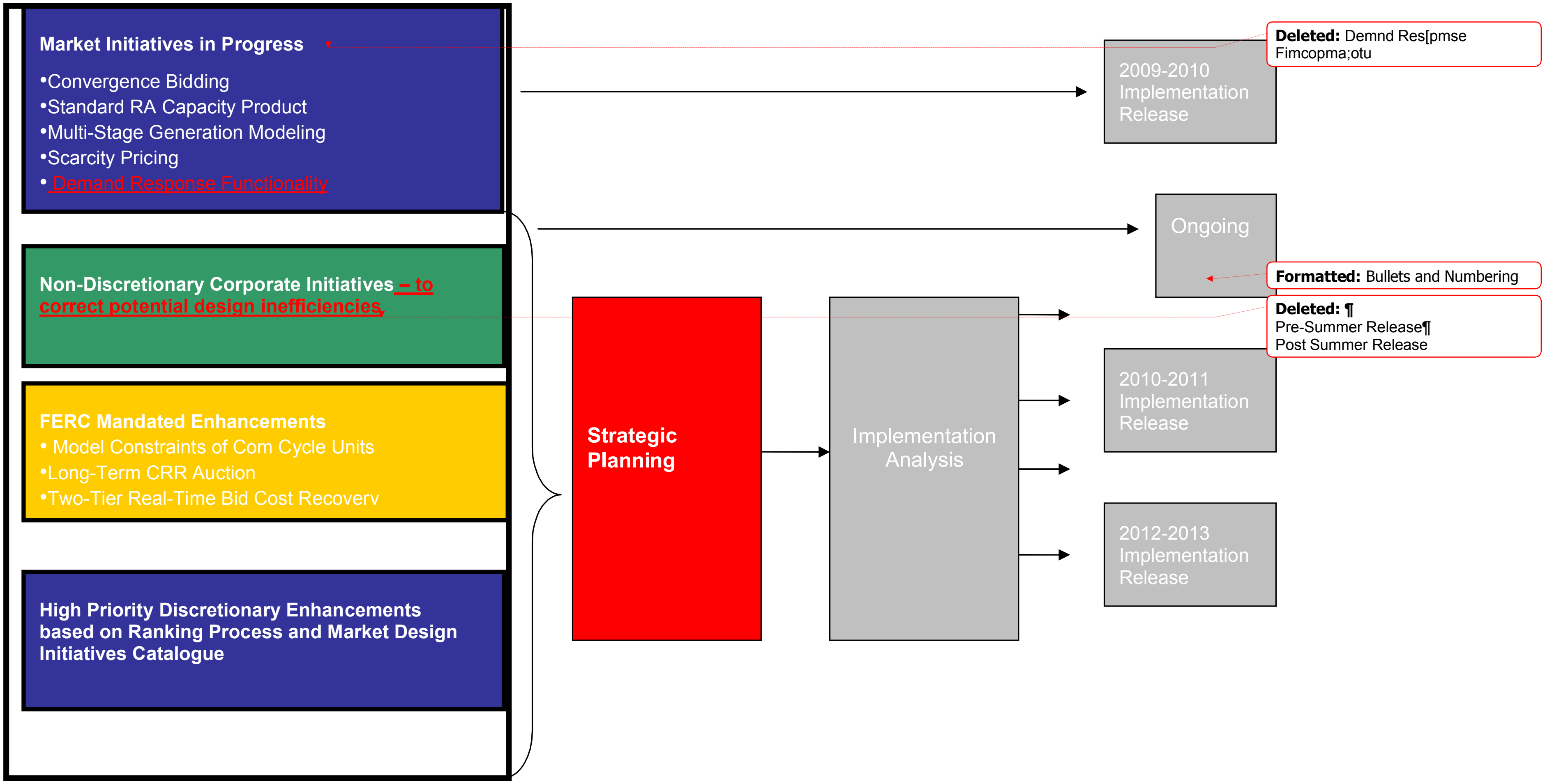
This catalogue is designed to capture design elements that could potentially be implemented to enhance ISO markets. It is important to keep in mind that there are initiatives which have completed the design phase that are now scheduled for testing and implementation.

Deleted: On June 24, 2009 the ISO will be hosting a stakeholder meeting to discuss the release schedule for these enhancements.[3]¶

[2] Refer to the "Five Year Strategic Plan Update" for 2009 - http://www.caiso.com/23a1/23a1760a411a0.pdf

[4] BPMs are posted on the ISO website and can be found at the following location: http://www.caiso.com/17ba/17baa8bc1ce20.html

Figure B – Market Initiatives Roadmap Process



D- Discretionary; F – FERC Mandated
I – In Progress/Planned; N – Non-Discretionary

2. Day Ahead Market Design

Since the start of the redesigned CAISO markets, the Day-Ahead Market (DAM) has been operating well, laying the foundation for a series of planned and optional market enhancements that are expected to further improve day-ahead price signals as well as the convergence of day-ahead and real-time market prices. The structure and rules for the DAM are presented in the Business Manuals for Market Operations and Market Instruments.[4]

2.1 Convergence Bidding and Related Initiatives

2.1.1 Convergence Bidding (F, I)

Convergence (or virtual) bidding is a mechanism whereby market participants can make financial sales (or purchases) of energy in the day ahead market, with the explicit requirement to buy back (or sell back) that energy in the real time market, thereby potentially moving the day ahead and real time prices closer together.

FERC's 9/12/06 MRTU Order (P 430-452) required the ISO to implement convergence bidding within 12 months of the launch of the new market. FERC's 4/20/07 Order (P 105-119) specified that the ISO must file tariff language for the implementation of convergence bidding no later than 60 days prior to the one year anniversary of new market (MRTU) launch.

The ISO is currently engaged with stakeholders to develop the conceptual design for convergence bidding and will continue stakeholder discussions to determine the granularity, cost allocation and other design features for convergence bidding. Related documents and written stakeholder comments are posted at:

http://www.caiso.com/1807/1807996f7020.html

FERC's 9/21/06 Order also found that the harm of further delaying the substantial benefits of MRTU outweigh the potential benefits that are to be gained by implementing convergence bidding in the new market, but agreed with commenters that it must include provisions to offset LSEs' incentive to underschedule in the day-ahead market. In March 2009 FERC approved the ISO Interim day ahead underscheduling tariff provisions (See Section12.1.9 – Interim Measures to Address Day Ahead Underscheduling).

Status: The stakeholder process for convergence bidding resumed in July 2009. The ISO will seek approval on the design of convergence bidding from the ISO Board of Governors in December 2009.

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2.1.2 Day Ahead Market Power Mitigation Based on Bid in Demand (I)

In a 2005 review of MRTU LECG suggested the use of bid-in demand rather than demand forecast in pre- integrated forward market (IFM) passes in the day ahead market. LECG also recommended eliminating use of extreme DEC bids in Pass 2 pre-IFM for schedules selected in the Pass 1, and unrestricting the pool of resources in IFM and RUC based on unit commitment in Pre-IFM.

FERC's 9/21/06 MRTU Order (P 1089) conditionally accepted the ISO's proposal to use forecasted demand in Pre-IFM passes, subject to the ISO instituting bid-in demand as the basis for applying market power mitigation in the pre-IFM runs no later than MAP Release 2 to reduce the likelihood of over-mitigation of suppliers.

As an outcome of the convergence bidding stakeholder process the ISO is proposing that market power mitigation based on bid-in Demand be implemented concurrently with - convergence bidding in MAP. Since virtual bids may impact the market power of physical bids they should be considered in the day ahead market power mitigation process even though they would not actually be mitigated like physical bids.

Since the MPM-RRD run will use bid-in Demand, it is possible for virtual supply bids to commit less than the minimal RMR generation that is needed to for voltage support in local areas. The ISO anticipates that, assuming convergence bidding will not likely be introduced in the near future, the reduced number of available RMR units could be committed manually on a daily basis. The ISO anticipates any manual commitment of needed RMR units would occur after the IFM run, but before RUC is run (giving the RMR units the “market first” opportunity in the day-ahead IFM)

More information can be found in the white paper “Updates on the Design for Convergence Bidding posted on the ISO website at:

http://www.caiso.com/1c8f/1c8ff39f65a70.pdf

Status: There is no change to this initiative. It is a sub-issue of convergence bidding and will be implemented with convergence bidding.

2.2 Two-Tier rather than single-tier Real Time Bid Cost Recovery (BCR) Allocation (F)

The existing real time BCR cost allocation for new market consists of a single tier charge that is allocated to Measured Demand. In the September 21 Order, FERC ordered the ISO to file tariff language reflecting such an approach. Stakeholders raised concerns regarding the single tier approach and have requested that the ISO implement a two tier charge similar to day ahead Bid Cost Recovery where the first tier would allocate costs based on cost causation principles.

In the FERC April 20th Order the ISO was directed to work with stakeholders to develop a proposal for two-tiered allocation of real-time bid cost recovery costs that could be included within three years after the new market launch.

Throughout the convergence bidding stakeholder process this issue has been raised as a significant issue that a number of stakeholders desire to be resolved concurrently with the implementation of convergence bidding. The issue was also prioritized as high by certain stakeholders during the MAP scoping stakeholder process.

2008 Rank: – Medium

Status: An issue paper was published in October 2008 that outlined some ideas for creating a two-tier structure for real time Bid Cost Recovery. This issue paper was discussed at a convergence bidding stakeholder meeting held in November 2008. The ISO resumed discussions on this topic at the July 2009 convergence bidding stakeholder meeting. The issue paper is posted on the ISO website at:

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http://www.caiso.com/205b/205bf1653cf60.pdf

2.3 Scarcity Pricing (I)

The current market design provides for scarcity pricing for energy; however, no explicit measures are included for scarcity pricing of reserves. Reserve prices may exceed the bid cap to the extent of the opportunity cost of energy. In other words, Reserve prices will generally be limited to the sum of the prevailing bid cap for Reserves plus the prevailing bid cap for energy. FERC's 9/21/06 MRTU Order (Paragraphs 1077 to 1079) found that the ISO's initial scarcity pricing approach is too narrowly tailored, and that prices should rise to reflect the increased need for reserves and energy, whether or not the shortage arises in conjunction with a generation or transmission outage, in both the day-ahead and real-time markets. While FERC concluded that the ISO's limited scarcity pricing approach is a reasonable start for implementation of the new market, the ISO should further refine its proposal to include a more broadly-triggered reserve shortage scarcity pricing, and on a more accelerated basis, to ensure that prices are not inappropriately suppressed during periods of genuine scarcity. The Order directs the ISO to file tariff language for the implementation of an expanded scarcity pricing methodology within 12 months of the effective date of new market. Furthermore, the Order directs the ISO to develop a reserve shortage scarcity pricing mechanism that applies administratively-determined graduated prices to various levels of reserve shortage, to be implemented within 12 months after MRTU launch.

The ISO started its stakeholder process for development of post-MRTU Scarcity Pricing mechanisms in June 2007. Since then the ISO has hosted several stakeholder meetings discussing the proposal for Scarcity Pricing design. The proposal has been updated over time based on the feedbacks from stakeholders.

Status: The ISO stakeholder process has been on hold since July 2008 to focus on the startup of MRTU. The process will resume in late summer 2009. This schedule allows both the ISO and stakeholders to gain experience relevant to the design of Scarcity Pricing from the operation of the new market. The ISO plans to present the final design of Scarcity Pricing to the ISO Board of Governors for decision in December, 2009. All versions of the proposal and stakeholder written comments can be found at:

http://www.caiso.com/1bef/1bef12b9b420b0.html

2.4 Multi-Day Unit Commitment in the IFM (D)

Currently, the forward looking time horizon in IFM is one day, taking into account the impact of prior commitment of units with very long start up times. During the MRTU Stakeholder meetings there were requests that the ISO make commitment decisions in the IFM that look out beyond a single day in order to create a commitment decision that is more efficient and better reflects the impact of startup-up cost for resources that have long start-up times. There are several design issues, including the need for bidding and bid replication rules as well as software performance and solution time requirements that must be discussed and resolved via a stakeholder process before considering modification of the software to accommodate Multi-Day unit commitment in IFM.

As the ISO completed its design for new market, the ISO found that there is an opportunity to run an optimization process, "Extremely Long-Start Commitment" (ELC), following the Residual Unit Commitment (RUC) process. The RUC process is able to consider unit commitment to meet the ISO's forecasted demand for generators with up to 18-hour start-up times, but there are a small number of generators with start-up times exceeding 18 hours. The ELC process gives the ISO the opportunity to determine when it should commit these generators, for reliability purposes, by using a 48-hour optimization period. Further details of the ELC process are available in section 6.8 of the BPM for Market Operations, at:

https://bpm.caiso.com/bpm/bpm/version/000000000000005

There may be limitations on the economic optimality that can be achieved by using separate ELC, RUC, and IFM processes, but these may be unavoidable due to assumptions that bids submitted to the day ahead market will be applicable on the following day.

2008 Rank: Medium

Status: The Extremely Long-Start Commitment (ELC) functionality was deferred from the launch of the new ISO markets due to the fact that its development was not complete. There are currently only 15 Extremely Long Start (ELS) units amounting to 6,639 MW of total generating capacity, and so the ISO Board of Governors (October 2008) agreed with Management's recommendation that the commitment of these units be done manually until the automated process could be implemented. The FERC tasked the ISO with conducting a Stakeholder process to determine the need for an automated ELC process (Docket No. ER09-213-000).

In the interest of efficiency, the ISO will merge the evaluation of the Multi-Day Commitment (MDC) initiative with this ELC Stakeholder process. Since implementation of MDC would also serve to effectively dispatch ELS units, the merging of these efforts will result in less design and implementation work than doing each of them separately. In addition, it is probable that the design and implementation work associated with MDC will not be substantially greater than that of doing ELC alone.

2.5 Day Ahead Scheduling of Intermittent Resources (D)

Based on comments submitted by stakeholders in 2008, and with the market operating experience to date, CAISO is evaluating how to provide appropriate incentives for day-ahead scheduling by intermittent resources or other entities that could provide proxy schedules or Bids that reflect the impact of intermittent resources on the market. As discussed here, relevant topics may emerge in several different areas of market design. The PIRP program design for the market only requires that intermittent resources submit a schedule into the HASP equal to the Hour Ahead PIRP forecast to qualify for the program. By not having expected intermittent resource energy included in the day ahead IFM, the day ahead market solution is incomplete, adversely influencing day ahead LMP, congestion and RUC awards. As intermittent resources, both solar and wind, become a larger percentage in the California energy supplies, the ISO should take steps to ensure this energy is fully incorporated into the IFM, either by creating incentives for PIRP wind resources to schedule or through convergence bidders that might take day-ahead positions that correspond to expected wind output in real-time.

Other issues to consider are:

- day ahead market (DAM) wind scheduling looking at (a) how much wind can be scheduled day ahead, (b) will LMP be calculated based on this value or the ISO's own forecast, and (c) how will DA wind schedules affect RUC decisions.
- The day-ahead ancillary service market changes (e.g., the additional Regulating reserves forecast by the CAISO's 2007 Renewable Integration report) .

2008 Rank: Low

2.6 Demand Response

2.6.1 Proxy Demand Response (I)

FERC Order 719, which was issued in October of 2008, requires that ISOs permit DR aggregators also known as a Curtailment Service Provider (CSP) to bid demand response on behalf of retail customers into the organized energy markets. In response to the FERC Order 719 requirements as well as the request from market participants for a product that would better accommodate existing Demand Response retail programs; the ISO developed the concept of the PDR product. The proposed PDR product was developed based on feedback from market participants that the Participating Load functionality available at MRTU launch and the proposed refinements to Participating Load did not provide flexibility needed to incorporate price responsive Demand Response programs into the ISO markets. Specifically, the PDR Product addresses the following challenges:

- Allows the Curtailment Service Provider (CSP) to bid Demand Response directly into the ISO's energy and ancillary service markets and to participate separately from the LoadServing Entity (LSE) as required by FERC Order 719
- Allows retail DR programs that are imbedded as part of the Investor-Owned Utility's (IOU) load to participate in the ISO energy and ancillary services markets
- Enables the underlying base load associated with the DR resource or program to be embedded in the LSE's overall load schedule at the Default LAP level, while a separate bid for DR, represented as a proxy generator, will represent the price-responsive demand within a Custom LAP

The ISO is currently engaged in a stakeholder process to finalize the design details for PDR and is planning to seek ISO Board approval in September 2009. All documents are posted on the ISO website at:
http://www.caiso.com/23bc/23bc873456980.html

2.6.2 Participating Load Refinements (previously Dispatchable Demand Response) (I)

The existing market software includes limited functionality to allow demand resources to participate directly in the ISO's wholesale markets. As part of the Markets and Performance (MAP) initiative, the ISO will complete the functionality that was intended to be part of the original MRTU market design.

The refinements to be implemented as part of the ISO's Market and Performance (MAP) initiative provide a flexible model for Participating Loads that allows a single resource to both schedule demand and bid load curtailments as an integrated bid, which can use co-optimization of Energy and Ancillary Services in both the day ahead and real time markets to determine the best utilization of the demand response resource. The refined functionality will effectively provide demand response resources with full comparable functionality to that of a generator in the ISO's markets. This design provides considerable flexibility for demand response resources, allowing Participating Loads to (1) simply bid into the ISO markets with a forward Energy Bid, (2) provide additional details about the operating characteristics of the demand response resource like Minimum Load Reduction (minimum MW of demand response),Minimum and Maximum Load Reduction Time, and Minimum Load Reduction Cost in addition to the Energy Bid, or (3) provide capacity for Residual Unit Commitment (RUC) and/or as Non- Spinning Reserve or other Ancillary Services (A/S).

The September 21, 2006, FERC Order on MRTU, as well as FERC Orders since then, directed the ISO to work with market participants to present additional opportunities for Demand Response resources to participate in the ISO Markets. The ISO has responded to these orders through the implementation of the participating load refinements as well as through the introduction of Proxy Demand Resource which is described in Section 2.5.1 above.

The Final Proposal for Participating Load Refinements is posted at:

http://www.caiso.com/239e/239e704828350.pdf

2.7 Dynamic Pivotal Supplier Test for Market Power Mitigation (D)

Local Market Power Mitigation in the new market is accomplished through prior classification of transmission constraints as "competitive" or "non-competitive". The question here is whether this process should (or could) be replaced by "on-the-fly" determination of pivotal suppliers in the market-clearing process.

2008 Rank: Medium

2.8 Bid Cost Recovery (BCR) for Units Running over Multiple Operating Days (F)

Currently, eligibility for BCR is determined for each operating day. Within each operating day, the revenue received for a unit net of start-up and minimum load costs is evaluated. If this net revenue value is negative, the unit is eligible for BCR for that operating day. This does not adequately consider instances in which a unit's run time crosses over from one operating day into the next. Because the BCR calculation does not determine eligibility based on the entire run time of the unit, but rather evaluates each operating day individually, it is likely that eligibility for BCR is inflated. Market participants therefore bear higher uplift charges. This initiative aims to institute a change to the BCR calculation to reflect the true net revenue of units with run times that cross operating days.

In FERC's September 21 Order (paragraph 533) the ISO was directed to "develop and file with the Commission a plan for units facing these types of constraints for implementation no later than MRTU Release 2".

2008 Rank: Medium

Status: In order to assess the magnitude of the issue, the ISO will use data from the first year of new market operation. Specifically, the ISO will analyze the frequency with which units operating over more than one operating day are eligible for BCR in one or both days but wouldn't be eligible if their entire run time were considered thus netting the operating days against one another.

2.9 Extension of Bid Cost Recovery to Transactions Other than Internal Supply (N)

Currently, the ISO settlements process provides BCR only for supply resources internal to the control area. This policy was based on the assumption that the need for BCR is driven primarily by operating constraints on supply resources and that for other resources; the market results would always be consistent with the cleared bids. In practice, this is generally the case. When market results require corrections or when uneconomic adjustments occur between the scheduling and pricing run, however, settlement prices can differ [deleted 'substantially'] from the value of the cleared bids. Establishing BCR for other resources will enable these resources

Deleted: with Run Times that exceed 24 hours

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to be "made whole" when prices are adjusted in a way that is not consistent with their accepted bids. Thus this initiative would provide other resources the same assurances of BCR as are made for internal generation.

2.10 Treatment of Use-Limited Resources with Limited Number of Hours or Start Ups (D)

Use-limited resources accommodated in the new market are those with Energy (MWh) limitations. This issue would explore how to incorporate software capability to accommodate other types of use limitation, including limitation on the number of hours of usage, or the number of start-ups a resource may be used for, during the scheduling horizon. Such an evaluation would also consider whether alternatives exist for this type of functionality, since the combination of start-up time, minimum run time, and minimum down time will inherently limit the number of start-ups for a resource during a day, and the incurrence of start-up costs can cause the market optimization to minimize the number of start-ups per day.

2008 Rank: Low

2.11 Load Aggregation Point (LAP) Granularity (F)

FERC's 9/21/06 Order on MRTU found that the ISO's approach to calculating and settling energy charges for load based upon three LAP zones provides a reasonable and simplified approach for introducing LMP pricing, while minimizing its impact on load. The Order recognized that some areas could experience higher prices under a nodal model, thus making it desirable to soften the distributional impacts of LMP, and also recognized that LMP could create an economic hardship on entities located in load pockets. Accordingly, FERC approved the ISO's proposal of three major LAP zones as an acceptable starting point. However, the Order directs the ISO (Paragraph 611) to increase the number of LAP zones within three years after the launch of the new market, to provide more accurate price signals and assist participants in the hedging of congestion charges.

FERC's 9/21/06 MRTU Order (Paragraph 614) noted that previous guidance orders had asked the ISO to consider an eventual move to nodal pricing for load, and directed the ISO to move to nodal pricing for load in the future.

FERC's 4/20/07 MRTU Order (Paragraphs 314-331) FERC further directed the ISO to increase the number of LAP zones within three years after MRTU launch.

2008 Rank: Low

2.12 Marginal Loss Hedging Products (D)

Marginal transmission losses can be a significant cost and cost uncertainty for SCs under MRTU. The ISO should investigate the feasibility of developing mechanisms or product(s) for hedging uncertainties with respect to the magnitude of marginal transmission losses.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2008 Rank: Low

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Deleted: <#>Start Up Energy Considered as Instructed Energy during Dispatch (D)¶
The MRTU design did not explicitly recognize the time lapse from unit synchronization to operations at its minimum stable operating unit. Any Start Up Energy, i.e., energy produced during the time interval from synchronization to minimum load, is assumed to be uninstructed deviation. This issue would explore how Start-up Energy might be considered as instructed energy during the dispatch process. Various stakeholders have suggested that some resources may take time to ramp to minimum load, and that better recognition of this start-up ramp would better reflect the imbalance energy needs and reduce uninstructed deviations during resource start-up.¶
2008 Rank: Low¶
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2.13 Ability to Bid Start Up Costs and Minimum Load Costs and Market Power Mitigation for Start Up and Minimum Load Cost Bids (D)

Currently SCs do not have the option to bid start-up costs and have the choice of either selecting proxy cost where the start up cost will be generated based on fuel prices or registered cost where the ISO will pull a registered value out of the master file for the start up cost. This suggested enhancement will allow SCs to bid start-up cost.

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There is an additional matter related to start up and minimum load cost related to bid caps. In response to concerns identified as part of the 2006 Market Initiatives Roadmap, the ISO developed bid caps for startup and minimum load bids submitted by generators under the six-month bid-based option for start up and minimum load bids.[5] The proposed caps were designed to be implemented by limiting bids that can be entered in the Master File, so that these caps could be applied as part of the new market design without changes in the actual market software. However, as part of the process of developing these bid caps, there was widespread support among stakeholders, DMM and the MSC for pursing a more dynamic approach under which startup and minimum load bids submitted under the six month bid-based option would be mitigated to default cost-based levels only when a unit was committed to meet a non-competitive transmission constraint.

Deleted: This issue was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

Deleted: 2008 Rank: Medium¶
Status: The ISO is currently developing a proposal to enable the bidding of Start-Up and Minimum Load costs on an hourly basis¶
<#>Market Power Mitigation of Startup and Minimum Load Cost Bids (D)¶
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The more dynamic approach that was discussed as part of this process would closely mirror how energy bids will be mitigated under the new market design, as well as how start up and minimum load bids submitted under the six month bid-based option are mitigated under PJM's market design. Specifically, if a unit was not committed under the Competitive Constraints Run (CCR) of the MPM procedures, but was committed under the All Constraints Run (ACC), the unit's startup and minimum load bids would be subject to mitigation to default cost-based levels. With this approach, it may still be necessary to retain some very high caps on startup and minimum load bids submitted under the six month bid-based option, since these bids would still be in effective.

2008 Rank: Medium and High respectively.

Status: Two catalogue items (Ability to Bid Start Up Cost and Minimum Load Costs and Market Power Mitigation of Start Up and Minimum Load Cost Bids) have been combined into one initiative since they are so closely linked. The ISO is currently developing a proposal to enable the bidding of Start-Up and Minimum Load costs on an hourly basis.

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2.14 Study of Marginal Loss Surplus Allocation to Regional Measured Demand (I)

In the June 2, 2006 Answer to Reply Comments on the MRTU Tariff that was filed on February 9, 2006, the ISO agreed to study the methodology for allocating the over-collection of marginal losses to measured demand on a regional basis, using available LMP studies. The purpose of this study is to determine a credible range of marginal cost of losses to serve the demand in Northern California (NP15 plus ZP 26) and Southern California (SP15), and a commensurate range of actual cost of losses in each region. A credible range of marginal loss surplus (MLS) rebate rate ($/MWh of Demand) for each of the two regions can then be determined and compared with system-wide marginal loss surplus rebate rate. If the system-wide MLS rebate rate falls outside the credible range of the regional MLS rebate rates beyond an acceptable

[5] See Five-year Market Initiatives Roadmap, 2008-2012, REVISED DRAFT – April _15_, 2008, Section 2.1.4, p.12

margin, a process for allocation of MLS based on Regional Measured Demand may then have to be worked out; in that case the exact methodology for Regional-based MLS allocation to Measured Demand will be carried out through a stakeholder process. A White Paper on the framework for this study is located at:

http://www.caiso.com/1831/1831d9532fd30.pdf

An interim simplified study was performed using 5 months of available LMP data (May through September 2004) with LMP decomposition based on distributed slack. A white paper is located at

http://www.caiso.com/184f/184f8ad86b730.pdf

In the September 21, 2006 MRTU Order, FERC accepted ISO's system-wide Marginal Loss Surplus allocation method as filed, but PG&E filed for rehearing requesting completion of the Marginal Loss study. In its answer, ISO agreed to complete the study using 12 months of LMP data (May 2004 through April 2005), and relaxing the shortcuts used in the interim study. The ISO has completed this study, and the resulting report is available at:

http://www.caiso.com/1bbf/1bbfd56174f50.pdf

Status: The conclusion of the ISO's study was that no change in its filed allocation method or the software was needed at market launch. The ISO will monitor the actual allocation results using the same study methodology to determine if a change in its filed method and/or software might be appropriate based on the actual market results.

Additional documents related to this issue are located at:

http://www.caiso.com/docs/2004/11/19/2004111912470915456.html

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2.15 Potential Modifications to Market Rules for Day-Ahead Intertie Schedules (D)

To improve reliable grid operation and clarify market rules, the ISO is considering tariff changes to clarify the timeline for submitting e-tags for imports and exports that are scheduled or accepted in the Integrated Forward Market (IFM).

Under current market rules, market participants may re-bid an import or export in the HASP that originally cleared the IFM. Currently, some import or export bids that clear the IFM are not tagged in the day-ahead timeframe (i.e. by the 3 p.m. deadline under WECC e-tagging guidelines). In these cases, it appears that some market participants only procure the resources to deliver on a bid and submit an e-tag in the event the bid also clears the HASP. Alternatively, if an import or export that originally cleared the IFM does not clear again in the HASP, the market participant essentially "buys-back" the import (or "sells-back" an export) at the HASP price.

The ISO is concerned that waiting until after the HASP to procure resources to deliver on day-ahead imports or exports has the potential to cause operational problems when supplies are tight. In this case, by the time a day-ahead import also clears the HASP, the market participant may not be able to find the resources (energy plus transmission) to deliver the import (alternatively, may not be able to deliver an export during over-generation). In especially tight supply periods, when the CAISO is relying on imports to meet its load obligations, internal load has priority in the HASP over bids to buy-back imports, virtually assuring that day-ahead imports will clear again in the HASP.

The lack of clarity about the timeline for tagging imports and exports that clear the IFM market also results in an asymmetry, where some market participants arrange resources for IFM import and export schedules and submit e-tags in the day-ahead timeframe, while other participants wait until after the HASP. This may place participants who arrange resources necessary to ensure that IFM schedules can be met at a competitive disadvantage relative to participants who wait until after the HASP to make arrangements to met final import and export schedules.

The ISO has identified several potential market rule changes that might address this issue, which include (1) requiring e-tags to accompany IFM import or export bids, (2) requiring imports or exports awarded in the IFM to be tagged in the day-ahead timeframe, or (3) requiring that an e-tag be submitted prior to the HASP for an import or export to be bought back at the HASP price and/or (4) establishing a penalty charge for imports or exports not tagged prior to the HASP.

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3. Hour-Ahead Market Design

The Hour-Ahead Scheduling Process (HASP) contains provisions to issue hourly pre-dispatch instructions to System Resources that submit energy bids in the real time market and for the procurement of A/S from those resources. For more details regarding HASP refer to the BPM for Market Operations.[6]

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3.1 Creation of a Full Hour-Ahead Settlement Market (D)

This issue is whether to augment the two-settlement market design of MRTU with a third Hour Ahead settlement market, which could be either a substitute for or in addition to the Hour Ahead Scheduling Process (HASP) element of the MRTU design.

2008 Rank: Low

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4. Real Time Market Design

The Real Time Market consists of the Real Time Unit Commitment (RTUC), Short Term Unit Commitment (STUC) and the Real Time Dispatch (RTD). For more details regarding the Real Time Market refer to the BPM for Market Operations.[7]

4.1 Rules to encourage Dispatchability of wind and solar resources (D)

Currently, wind resources that participate in the Participating Intermittent Resources Program (PIRP) become ineligible for the PIRP rules for settlement of imbalances if they submit price Bids into the RTM. This can create a disincentive for wind resources to offer Decremental Bids for purposes of efficient congestion management and management of overgeneration conditions. In addition, the current DEC Bid floor of $-30/MWh is considered by some wind resources to be insufficient to cover opportunity costs of being dispatched down (such as loss of Production Tax Credits). At the same time, projected increases in wind generation make it more important to provide incentives for such Decremental Bids. CAISO will begin a process in 2009 to evaluate the existing rules and incentives for wind to become more dispatchable, jointly with related design initiatives.

In their comments CalWEA, LSA and AWEA support this initiative and further suggest the following market design changes – a) change the PIRP rule to permit retention of monthly

[6] BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html
[7] Ibid.

netting of imbalances if real-time decremental energy bids are submitted and b) lower the $-30/MWh decremental energy bid floor.

4.2 Ramp Rate Enhancements (D)

Operational ramp rates are used for scheduling and dispatch in real time. In order to maintain performance of the software within the required solution timing parameters, the number of operational ramp rate segments supported in the new market design is limited to 4 (versus 10 segments initially contemplated). Only 5% of the resources with ramp rates operational ramp-rates defined in the Master File would have ramp rates with more than 4 segments defined. Some participants had concerns about the reduction in the number of ramp rate segments. After actual performance is determined, the ISO can work with its vendor to determine if additional operational ramp rate segments can be supported.

While a separate operating reserve ramp rate is used for procuring the spinning and non-spinning reserves, the operational ramp rate is used for all dispatching of a resource. To the extent the operational ramp rate at a given operating level is less than the Operating Reserve ramp rate, the resource may be subject to A/S “No-Pay” charge for reserves that are not actually available based on the lower operational ramp rate. Modifications to the software would be necessary to more closely align procurement of A/S with energy dispatch from A/S capacity in real-time.

2008 Rank: Low

4.3 Consideration of UFE as part of Metered Demand for Cost Allocation (D)

The State Water Project (SWP) in its MRTU filing to FERC requested that UFE be allocated load based costs also. In the filing SWP provided concept of “Gross Demand” incorporating metered demand and UFE that would replace metered demand for the purpose of cost allocation.

FERC did not disagree with the concept but rejected the case because the issue was raised late. A similar request was made by SWP with respect to WECC/NERC cost allocation, FERC accepted SWP’s proposal and ordered ISO to file compliance with the provision that metered demand and UFE would be allocated WECC/NERC charges.

2008 Rank: Low

4.4 Multiple Scheduling Coordinators (SCs) at a Single Meter (D)

On June 7, 2006, FERC issued an order directing the ISO to address the current prohibition on the use of multiple Scheduling Coordinators at a single meter. On July 12, 2006 the ISO posted a White Paper identifying various options for dealing with this issue, primarily addressing generation. The White Paper is located at:

http://www.caiso.com/1832/1832c86e1ade0.pdf

The City of Riverside has commented that full-scale implementation of the capability of multiple SCs in bidding, operation and settlement would be desirable.

SCE suggests the ISO should consider redirecting its limited staff to focus on other issues such as MRTU implementation.

Pursuant to the ISO's compliance filing on September 7, 2006, the FERC noted that at that time there was minimal stakeholder interest for pursuing an immediate software solution for the "Multiple SC at a Single Meter" issue.

More recently, discussions concerning the implementation of enhanced demand response following the launch of the new market have identified a potential role for demand response aggregators who would bid price-responsive demand separately from the initial scheduling of load by load serving entities. Before these could be implemented as separate roles, however, a number of issues about the structure of the retail electricity market would need to be resolved, including responsibility for financial settlements of real-time deviations from schedules and dispatches, and for communication between these entities during the scheduling process. The California Public Utilities Commission has identified these foundational policy issues as part of its development of demand response goals, and the ISO is participating in the formulation of these policies to ensure that they can be readily implemented in the ISO's markets once they are formulated.

2008 Rank: Low

4.5 Extend Look Ahead for Real Time Optimization (D)

The current real time market conducts a 5 hour "look ahead" optimization. As a result, during the operation day, the optimization will ignore units that have a start up time longer than 5 hours unless they are already running or committed. The optimization should have a process for looking forward for remainder of the entire day in order to commit units with longer start-up times.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2008 Rank: Low

5. Residual Unit Commitment (RUC)

The purpose of the RUC process is to assess the resulting gap between the IFM Scheduled Load and the ISO Forecast of ISO demand, and to ensure that sufficient capacity is committed or otherwise be available for dispatch in real time in order to meet the demand forecast for each trading hour of the trading day. For more details regarding RUC refer to the BPM for Market Operations.[8]

5.1 Multi-Hour Block Constraints in RUC (F)

SCE raised a concern that resources may be committed for a time period that is inconsistent with its offer, because RUC does not observe any multi-hour block constraints. "SCE requests that the ISO revise its software to honor multi-hour block constraints in RUC for MAP Release 2." (See SCE Comments on Market Initiatives, July 28, 2006, at:

http://www.caiso.com/1845/18459b7a4f300.pdf)

FERC's 9/21/06 MRTU Order (P 1280) finds SCE's request reasonable that the ISO should honor multi-block constraints as a bidding parameter for system resources in the RUC process, and reiterated the finding that the ISO should examine whether such software changes could be implemented by the launch of the new market, or to implement them as soon as feasible. In its

[8] BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html

application for rehearing, the ISO pointed out that the purpose of RUC is to procure capacity for potential dispatch in real time, when multi-hour block constraints cannot be enforced, and that the cost of implementing SCE's proposal would be significant. FERC granted the ISO's request for rehearing, and changed its order to direct the ISO to implement this feature in a future MAP Release.

2008 Rank: Medium

5.2 Simultaneous Residual Unit Commitment (RUC) and IFM (D)

In the current MRTU design Residual Unit Commitment (RUC) is performed after completion of the IFM and does not impact day ahead market energy, ancillary services (A/S), and congestion/CRR pricing and settlement. The issue here is whether to perform IFM and RUC simultaneously, and if so, how.

2008 Rank: Medium

5.3 Consideration of Non-RA Import Energy in the RUC Process (D)

Early in the 2005 MRTU stakeholder process it was suggested that import energy bids that were not cleared in the IFM could be considered in the RUC optimization by treating such bids in the same manner as the minimum load bids of internal generators that were not committed in the IFM. The question to consider is whether, in light of the treatment of imports in RUC as filed in the MRTU tariff, any additional provisions for considering imports in RUC are needed or appropriate

2008 Rank: Medium

5.4 RUC Self-Provision (D)

Because of limited interest by most market participants in RUC self-provision feature as a priority for MRTU, the ISO did not to include this feature for Start up. However, FERC's 9/21/06 MRTU Order (Paragraph 172) directs the ISO to continue to work with market participants on this issue, and to provide reasons for the inclusion or exclusion of RUC self-provision no later than three years after the launch of the new market.

2008 Rank: Low

6. Ancillary Services

The ISO procures four types of Ancillary Services (A/S) products -- Regulation Up, Regulation Down, Spinning Reserve, Non-Spinning Reserve -- in the day-ahead and real-time markets. Section 4 of Market Operations BPM describes these Ancillary Services.[9]

6.1 Ancillary Services Substitution (F)

FERC's 9/21/06 Order on MRTU found it reasonable for the ISO to limit Ancillary Services substitution opportunities to units that are in the appropriate location and whose bids clear in the relevant market, but directs the ISO (Paragraph 303) to address the possibility of added flexibility for substitution of the source of Ancillary Services in future releases of market design enhancements.

[9] [9] BPMs - http://www.caiso.com/17ba/17baa8bc1ce20.html

In its 4/20/07 Order, FERC reiterated that for MRTU, the Commission accepts the ancillary service substitution proposal, and that there was no basis for reversing the prior determination and for the ISO to address the issue of additional flexibility in future MAP releases.

2008 Rank: High

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6.2 Exports of Ancillary Services (F)

Under the new market design there is no formal mechanism or specific process for bidding for exports of A/S, or for scheduling on-demand export of A/S. The optimization does not reserve transmission capacity for this functionality. In the new market, a manual workaround has been provided for entities with on-demand obligation; to the extent transmission capacity is available (or must be reserved according to ETC/TOR rights). This issue would explore how to build the reservation of transmission capacity into the optimization so that market participants who might have an obligation to supply Ancillary Service energy in real-time to neighboring control areas can serve this obligation. FERC's 9/21/06 Order on MRTU (Paragraph 355) directs the ISO to develop software to support exports of ancillary services in the future through stakeholder processes and to propose necessary tariff changes to implement this feature no later than three years after the launch of the new market.

2008 Rank: Low

6.3 Multi-Settlement System for Ancillary Services (D)

LECG's February 2005 report stated that the lack of a full multi-settlement system for Ancillary Services that optimizes real-time reserves and settles deviations from day-ahead schedules at real-time prices could raise consumer costs when reserves scheduled in the day ahead market must generate energy in real time as a result of minimum run times, minimum down times or transmission constraints. The new market design calls for procurement of A/S in the day ahead market to meet 100% of forecasted real time needs, and then procures additional A/S incrementally in real time only to the extent that they are needed due to changes in system conditions or demand exceeding the day ahead forecast. Moreover, unless the Operating Reserves are designated as "Contingency Only", their energy will be dispatched economically, and if as a result the Operating Reserves fall below the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) Minimum Operating Reserves Criteria (MORC), ISO will procure additional Operating Reserves in real time. The question to be considered is whether to modify the new market design to create a multi-settlement A/S market as suggested by LECG.

If the ISO implements a multi-settlement system issue this would resolve the issue of Ancillary Services substitution described in Section 6.1 above.

2008 Rank: High

6.4 Ancillary Service Self-Provision at the Interties (D)

The new market design does not include the self-provision of Ancillary Services from interties. Import A/S can only be bid and must compete with import energy bids for the use of New Firm Use (NFU) transmission capacity. This issue explores whether A/S self provision from the inter-ties can be expanded as a potential MAP release feature.

As the ISO's detailed design of the new market progressed, the ISO considered the prospect that self-provision of A/S can be accommodated for dynamic imports. This prospect may be sufficient for the currently anticipated market needs. This topic may have overlapping issues with the direction in FERC's 9/21/06 Order on MRTU (Paragraph 326) to ensure that all provisions of ancillary services, self-provided or not, are subject to the same regional constraints. To the extent that this topic is considered further, this topic would be combined with section 6.2 (Exports of Ancillary Service) since the underlying issue of reserving capacity is common to both issues.

In an April 20, 2007 FERC Order Western raised concern that its Boulder Canyon Project customers in the ISO Control Area currently self-provide ancillary services from the Project over the intertie and into the ISO Control Area and that the September 2006 Order is unclear as to whether these customers can continue to self-provide ancillary services from Western's Control Area to the ISO Control Area. FERC directed the ISO to work with Western determine whether the ISO's work-around is acceptable to Western and to propose any tariff revisions no later than 180 days prior to the implementation of MRTU.

2008 Rank: Medium

Status: The "California Independent System Operator Joint Quarterly Seams Reports for the Fourth Quarter of 2008" indicated that Western's issue has been resolved. It states "To the degree Western has the authority to use power from Boulder Canyon to self-provide Ancillary Services for its Ancillary Service obligations to the CAISO; it is the CAISO's understanding that Southern California Edison may schedule self-provided Ancillary Services on behalf of Western from the Boulder Canyon Project using Existing Transmission Contract rights. Western should ensure that it has secured any necessary statements or agreements from Edison to effect this self-provision of Ancillary Services. For purposes of the CAISO's involvement in this matter, the CAISO confirms that self provision of Ancillary Services at the interties is possible under Existing Transmission contract rights or Transmission Ownership Rights."

6.5 Ability to Designate A/S Contingency Hourly (D)

In the new market design the designation of "Contingency Only" ancillary services is accommodated on a daily basis. This issue would explore provisions for hourly designation of "Contingency Only" A/S.

2008 Rank: High

6.6 Multi-Segment Ancillary Service Bidding (D)

In the new market, ancillary services bids consist of a single bid segment. In comments leading up to FERC's 9/21/06 Order on MRTU, Powerex requested that multi-segment bidding should be provided for some ancillary services. While FERC did not impose this requirement in the launch of the new market, FERC directed the ISO (Paragraph 341) to file a report, before making its MAP Release 2 filing, addressing the potential benefits of including this element.

2008 Rank: Low

6.7 A/S Maximum Capability Operating Limits for Spin and Non Spin (D)

This issue would address the concern that a Generator cannot define the maximum operating level for which Spin or Non-Spin capacity can be provided. Currently the Pmax is considered to be the maximum operating level that Spin and Non-Spin capacity can be provided. This is similar to the ability a Generator has to define a maximum regulating level This issue resulted due to concerns that the CAISO may be accounting for operating reserve capacity that may not be deliverable.

6.8 Addressing Ramping Capacity Constraints (D)

This issue is a potential solution to consider to better ensure that sufficient ramping capability beyond the necessary capability necessary to follow load to be able to respond to other volatility in imbalance conditions that is separate and not encumbered as operating reserve or regulation capacity.

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<#>Reliability Products ¶
The focus of this initiative is to determine how the ISO can meet its needs for reliability products and services in the most efficient manner, utilizing market mechanisms where effective. In the course of this assessment the ISO will also consider whether new products or services should be defined to meet reliability needs that are not fully met by existing products. The following products have been identified to date. ¶
Ramping Capacity Product

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6.9 Voltage Support Procurement (D)

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This issue involves the development of a methodology for competitive procurement of Voltage Support services.

The ISO presented papers on both Voltage Support and Black Start during a stakeholder conference call on June 29, 2006, which are available at:

http://www.caiso.com/181c/181ca4c9731f0.html

These papers concluded that there is a wide variety of procurement and cost allocation methods among markets around the world, and that further studies could consider a range of future options.

2008 Rank: Low

6.10 Black Start Procurement (D)

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This issue involves the development of a competitive procurement methodology for Black Start services.

The ISO presented papers on both Voltage Support and Black Start during a stakeholder conference call on June 29, 2006, which are available at:

http://www.caiso.com/181c/181ca4c9731f0.html

These papers concluded that there is a wide variety of procurement and cost allocation methods among markets around the world, and that further studies could consider a range of future options. In its 2009 Order on the revised pricing rules for Exceptional Dispatch, FERC has required that the ISO undertake a stakeholder process to examine potential for market-based procurement of voltage support, in part to reduce the frequency of Exceptional Dispatch.

2008 Rank: Medium

6.11 30 Minute Operating Reserve (D)

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During the stakeholder process of various market initiatives (CPUC Long Term Resource Adequacy proceeding, Scarcity Pricing) stakeholders have raised the potential benefits of a new ancillary services product to address 30 minute reliability contingencies. Under the current market ancillary services structure, potential contingencies that could be covered by a 30 minute product are addressed using 10 minute ancillary services products which could result in the ISO needing to procure ancillary services on a sub-regional basis in higher amounts than would otherwise be necessary to meet WECC operating reserve requirements. Additionally, if the ISO is unable to procure enough reserves through the market, Exceptional Dispatch would be used. An alternative that has been suggested is to develop a new 30 minute A/S product. In its 2009 Order on the revised pricing rules for Exceptional Dispatch, FERC has required that the ISO examine the need for such a new product to reduce the frequency of Exceptional Dispatch.

2008 Rank: High

Status: The ISO held a stakeholder process in the Fall of 2008 and determined that the 30 minute product was not justified at that time. The ISO will monitor the results of the new market and reconsider the issue in the future if necessary. The next required milestone is an informational report to FERC by August 1, 2009.

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7. Congestion Revenue Rights

This section describes enhancements to the ISO's rules and systems related to Congestion Revenue Rights (CRRs), including both short-term (i.e., one-year Seasonal and Monthly) CRRs as well as Long Term CRRs. CRRs are both allocated to load serving entities and auctioned to all market participants, and the MRTU Tariff establishes several distinctions in the CRR release process for CRR Year One compared to subsequent years. In the coming months the ISO will begin a stakeholder process to plan CRR Year 2 enhancements.

As this catalog is being completed for posting, the ISO is developing an issue paper and timetable for a stakeholder process on CRR enhancements, and will inform stakeholders in the near future as to the planned dates for these activities.

7.1 Economic Methodology to Determine if a Transmission Outage Needs to be Scheduled 30-Days Prior to the Outage Month (I)

Currently the ISO Outage BPM requires that all transmission outages must be scheduled with the ISO at least 30-days prior to the month in which they are planned to occur unless they fall under one of the three exemption criteria. However, the tariff currently indicates that only outages that have a significant economic impact need to be scheduled 30-days prior to the month. The ISO needs to develop a process that performs an economic analysis to determine if a specific outage must be schedule 30-days in advance. Such a process should consider the resulting flows and costs associated with an outage and would exempt outages below a certain cost threshold from the 30-day scheduling rule. It is important for the ISO to develop an outage reporting schedule (minimum of one month's notice) that is adequate to support the revenue adequacy of congestion revenue rights.

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This was added to the catalogue based on comments submitted by two market participant in April 11, 2008 comments.

2008 Rank: Medium

Status: The ISO intends to begin this study after data has been gathered under the new market. The ISO would like to have at least a year of market experience before beginning this study.

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7.2 CRR Source Verification after CRR Year One (D)

The current tariff provides for CRR source verification in conjunction with CRR allocation to LSEs serving internal load only for CRR Year One. FERC's July 6, 2007 Order on Long Term CRRs (Paragraph 100) encourages the ISO to consider implementing some form of source verification process in CRR Year Two and beyond.

Documents related to the stakeholder process on various CRR issues, including whether to re-do source verification for certain Seasonal CRRs, are located at:

http://www.caiso.com/1b8c/1b8cdf25138a0.html

The ISO Board of Governors approved this initiative at the May 2008 Board of Governors Meeting.

Status: This is still an open item and should be prioritized with the other discretionary items.

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7.3 Long Term CRR Auction (F)

The ISO's January 29, 2007 compliance filing on Long Term CRRs noted that several parties wanted the ISO to implement an auction process for Long Term CRRs, which the ISO agreed to consider for a future release. FERC's July 6, 2007 Order on CRRs encourages the ISO to initiate the stakeholder process and file tariff language to implement an auction for residual Long Term CRRs in a future release of the new market. The 2008 ranking process demonstrated that this item is considered high priority due to its expected market efficiency benefits and the high level of stakeholder desire for it.

In identifying this item as high priority, the ISO notes that it would be logical to combine it with two other CRR-related items which individually were not ranked high in the 2008 process: (1) multi-period optimization algorithm for Long Term CRRs (section 9.6 below), and (2) flexible term lengths of Long Term CRRs (section 9.5). In addition it would also be logical to include a third item with these other items, namely, sale of CRRs in the CRR auctions (section 9.4, provided below). In the 2008 ranking process, however, that item ranked high by itself and therefore is retained in the present document as a separate item that could be implemented independently of a Long Term CRR auction. If the ISO and the stakeholders decide to move forward with a Long Term CRR auction, then the ability to sell CRRs in the auctions would be included in the scope of that effort if it is not implemented sooner.

The multi-period optimization algorithm, for which the April 15th Roadmap discussion is provided below, was already recognized by the ISO as an important CRR enhancement to enable the Long Term CRR release process to recognize future changes in transmission encumbrances over the horizon of the nominated Long Term CRRs (mainly the expiration of ETCs, CVRs and previously-released Long Term CRRs). The multi-period optimization algorithm will thus enable the ISO to find a more optimal balance between the competing objectives of releasing as many Long Term CRRs to the market as possible while minimizing the risk of CRR revenue inadequacy. In the context of an auction for Long Term CRRs, the multi-period optimization will result in auction prices that more accurately reflect the expected values of the Long Term CRRs being awarded. The ISO therefore believes that the multi-period optimization algorithm is an essential component of a Long Term CRR auction.

With regard to flexible term lengths for Long Term CRRs (see Section 9.6 below), the implementation of the multi-period optimization algorithm will make it possible to allow additional choices by market participants beyond the current single 10-year term provided under the existing rules. The exact nature of the allowable choices will be a topic for discussion with stakeholders as the policy and design of this item are developed.

2008 Rank: High

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7.3.1 Flexible Term Lengths of Long Term CRRs (D)

FERC's July 6, 2007 Order on CRRs encourages the ISO to consider future flexibility to allow: (i) Long Term CRRs in excess of 10 years, or (ii) annual CRRs with guaranteed renewal rights up to year 10, or (iii) Long Term CRRs with terms ranging from 2 to 9 years. FERC notes that any subsequent change in the available term lengths would have to respect the rights of the holders of any outstanding 10-year CRRs.

2008 Rank: Low

7.3.2 Multi-period Optimization Algorithm for Long Term CRRs (D)

When the ISO performs the initial release of Long Term CRRs for the period 2008-2017, the Simultaneous Feasibility Test (SFT) optimization will treat the entire 10-year time horizon as a single time period (for each combination of Season and Time of Use period) with respect to network model assumptions. The ISO has recognized that a multi-period algorithm can result in a more optimal allocation of Long Term CRRs because it would be able to reflect different assumptions for each year regarding the availability of grid capacity for CRRs, in particular the known expiration of previously released Long Term CRRs, Existing Transmission Contracts and Converted Rights. FERC's July 6 Order affirms that if the ISO and its stakeholders choose to implement the multi-period algorithm, the ISO must make a compliance filing within 30 days explaining the reasons for the change, how the change will affect Long Term CRR nominations, and how the change has been tested. The ISO had planned to develop this functionality in time for the CRR Year Two release process, but is now deferring implementation of this feature beyond CRR Year 2.

2008 Rank: Low

Status: Although theoretically "Flexible Term Lengths of Long Term CRRS" and "Multi-period Optimization Algorithm for Long Term CRRS" can be implemented separately, it makes sense to bundle them together, as we have done in this version of the catalogue. They will be ranked as one item.

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7.4 Sale of CRRs in the CRR Auctions (F, I)

The CRR systems at present have functionality to allow a party to offer for sale in an ISO CRR auction some of the same CRRs that were previously awarded in an auction or allocation process. The systems do allow the party to engage in a financially equivalent transaction, but this equivalent transaction results in the party holding two equal and opposite CRRs that net out financially, rather than allowing an actual transfer of the original CRR. For example, if the party holds a CRR of 10 MW from source A to sink B and wants to sell that CRR in a ISO auction, under the CRR Year One functionality the party cannot offer to sell that exact CRR, but must offer to buy at a negative price (assuming the original A to B CRR has positive expected value) a CRR of 10 MW from source B to sink A. If this offer clears the auction, the party ends up holding two 10 MW CRRs, one from A to B and another from B to A, and receives payment for the negative auction clearing price of the B to A CRR which should be the same as the price the party would have received for selling the A to B CRR at a positive price.

Of course, the party also has the option of selling the original A to B CRR bilaterally and then registering the bilateral transaction in the ISO's Secondary Registration System, but several parties have previously indicated in the stakeholder process that the ability to offer CRR holdings for sale in a ISO auction process would enhance the efficiency of the CRR market. FERC's September 21, 2006 MRTU Order affirms that it would be useful to have this feature, and the ISO has planned to consider this functionality among the enhancements to the CRR systems for CRR Year Two. The September 21 Order directs the ISO to file tariff language to implement the ability to sell CRRs in the CRR auctions no later than MAP Release 2.

2008 Rank: High

7.5 Revised Approach for Releasing and Tracking CRRs having a Trading Hub Source or Sink (D)

The current rules for handling CRR nominations sourced at a Trading Hub in the allocation process use a "disaggregation" approach whereby such nominations are disaggregated or unbundled into individual Point-to-Point CRRs each of which has as its source a Generating Unit PNode that is a constituent of the Trading Hub. Such nominations are then submitted to the optimization and eventually awarded to the nominating LSE in the unbundled form. Two concerns have been identified with this approach.

First, although the CRR Sources in the awarded "bundle" are expected to closely resemble the composition of the Trading Hub, the bundle will in general not match the Trading Hub exactly. FERC's July 6 Order directed the ISO to consider whether to develop software to assist LSEs in the trading of Trading Hub CRRs by "rebundling" individual PNode CRRs to reconstitute a Trading Hub CRR. More generally the ISO is also required by the Order to make a compliance filing within 6 months after the launch of the new market that explains whether the disaggregation method remains appropriate.

Second, the disaggregation approach can result in large numbers of fractional-MW CRRs, due to the fact that a trading hub may be comprised of a few hundred constituent generator PNodes. These fractional-MW CRRs can be further broken down into even smaller and more numerous individual point-to-point CRRs through other CRR processes, such as the transfer of CRRs between LSEs to account for migration of direct access load. The result is a population of CRRs whose management is burdensome for CRR holders as well as the ISO.

2008 Rank: Low

7.6 Release of CRR Options (D)

FERC's July 6, 2007 Order on CRRs urges the ISO to continue exploring the feasibility of implementing option CRRs in a subsequent market release.

2008 Rank: Low

7.7 Use of "Weighted Least Squares" CRR Optimization Algorithm (D)

Under the current algorithm, when two or more CRR allocation nominations by different LSEs compete for limited transfer capacity on a binding transmission constraint, the optimization algorithm will try to maximize the amount of CRRs released by reducing the CRR nomination that has highest effectiveness in relieving the constraint. The advantage of this approach is that the total overall MW of CRRs released is maximized. An undesirable side effect, however, is that the reduction in awarded CRRs due to the constraint will typically fall entirely on the one LSE that nominated the most effective CRR. In previous stakeholder discussions this aspect of the optimization algorithm was identified as a feature we could not change for CRR Year One. A possible alternative the ISO now wants to discuss with stakeholders at a later time is to utilize a "weighted least squares" algorithm that would allocate shares of the constrained transmission facility to each CRR nomination that has some effectiveness on the constraint. Although this approach will typically result in fewer total CRRs being allocated, it may be considered a more equitable approach to CRR allocation because it distributes the impact of the constraint across all LSEs whose nominations contribute to that constraint.

As a final point, note that the problem described is really only a problem in the CRR allocation processes. In the CRR auction processes the objective of the optimization algorithm is to maximize net auction revenues and therefore the bid prices are also taken into account in any

Deleted: <#>Flexible Term Lengths of Long Term CRRs (D)¶
FERC's July 6, 2007 Order on CRRs encourages the ISO to consider future flexibility to allow: (i) Long Term CRRs in excess of 10 years, or (ii) annual CRRs with guaranteed renewal rights up to year 10, or (iii) Long Term CRRs with terms ranging from 2 to 9 years. FERC notes that any subsequent change in the available term lengths would have to respect the rights of the holders of any outstanding 10-year CRRs. ¶
2008 Rank: Low¶
<#>Multi-period Optimization Algorithm for Long Term CRRs (D)¶
When the ISO performs the initial release of Long Term CRRs for the period 2008-2017, the Simultaneous Feasibility Test (SFT) optimization will treat the entire 10-year time horizon as a single time period (for each combination of Season and Time of Use period) with respect to network model assumptions. The ISO has recognized that a multi-period algorithm can result in a more optimal allocation of Long Term CRRs because it would be able to reflect different assumptions for each year regarding the availability of grid capacity for CRRs, in particular the known expiration of previously released Long Term CRRs, Existing Transmission Contracts and Converted Rights. FERC's July 6 Order affirms that if the ISO and its stakeholders choose to implement the multi-period algorithm, the ISO must make a compliance filing within 30 days explaining the reasons for the change, how the change will affect Long Term CRR nominations, a ... [2]

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Deleted: <#>Revised approach for releasing and tracking CRRs having a Trading Hub source or sink

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reductions of bid MW to relieve constraints. Auction participants can use their bid prices to express the relative value they place on obtaining CRRs that impact congested transmission facilities.

2008 Rank: Medium

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7.8 Transition to Auction Revenue Rights System (D)

The initial design of the Congestion Revenue Rights release process, as developed through an extensive stakeholder process during 2005, consists of a process for allocating CRRs to eligible Load Serving Entities, followed by an auction process that enables all creditworthy parties to obtain CRRs both for managing their congestion cost exposure and for speculative purposes. An alternative approach that was considered but rejected during the 2005 design process would be not to allocate CRRs directly to eligible LSEs, but instead to release all available CRRs through an auction process and to allocate shares of the net auction revenues to those LSEs that would otherwise have been eligible for CRR allocation. At the time it was recognized that such an “Auction Revenue Rights” or “ARR” approach to CRR release would offer considerable administrative simplification to the CRR program (to effect transfers of CRRs to reflect direct access load migration, for example), would provide maximum flexibility to all CRR Holders to restructure their CRR portfolios to best meet their business needs, and would ensure deep and liquid CRR auction markets for efficient pricing of all CRRs (important for setting CRR credit requirements, for example). Indeed, for the same reasons the eastern ISOs that started with direct allocation of financial transmission rights to LSEs have since converted to ARR systems. Although the dominant preference among ISO stakeholders was to start the LMP markets with a system of direct allocation of CRRs to eligible LSEs, the ISO understood that this design decision was not necessarily intended as the permanent approach for releasing CRRs. Once participants have gained some practical operating experience with CRRs and with the LMP markets in general, the ISO believes it would be valuable to look again at the potential benefits of an ARR system and consider transitioning to such a system. The ISO further suggests that this initiative could be undertaken in conjunction with the initiative to develop an auction process for releasing Long Term CRRs, which FERC has directed the ISO to consider in the MAP Release 2 time frame and is identified elsewhere in this section of the Roadmap.

2008 Rank: Medium

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7.9 Revise Load Migration Process (N)

As the ISO’s implementation of the process to reflect load migration on CRR ownership is completed, the CAISO is considering the prospect of gaining efficiencies in the production process. Under current design, the ISO carries out the production task in two main steps. In a first step, the percentage of load being transferred between Load Serving Entities (LSEs) is estimated based on data of customer transfers provided by UDCs. In a subsequent step, the transfer of Congestion Revenue Rights is calculated between LSEs using the percentages from the first step as the reference.

Since the original efforts of this initiative, the first step of this process has been highly convoluted due primarily to the need of receiving confidential data owned by UDCs. The current process requires that UDCs submit data in different files following a specific format within a particular timeframe. Since all input data is prepared by UDCs and the design requirements to compute the percentage of load migration have been finalized, ISO wants to explore the alternative of having the first step of the process carried out by UDCs. This will eliminate cumbersome steps of uploading and maintaining confidential data by the ISO.

Status: This initiative has been changed from discretionary to non-discretionary, so it is not part of the ranking process. The implementation of this initiative is required to comply with regulatory mandates.

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8. Resource/Supply Adequacy Initiatives

The broad area of Supply Adequacy includes primarily activities in which the ISO is a participant but does not play a lead role, although in most activities the ISO does have very specific and essential roles and responsibilities. In addition most – but not all – of the initiatives included in this area fall under state or local regulatory jurisdiction rather than under FERC jurisdiction.

The larger share of activities that will ultimately support Long Term System Security are being conducted under the procedural umbrella of the CPUC's Long Term Procurement Plan (LTPP) Rulemaking. This CPUC rulemaking includes the Phase 1 and Phase 2 Resource Adequacy proceedings as well as several more narrowly focused activities such as the Demand Response proceeding, all of which are discussed in the next four sub-sections, the first of which provides an overview of the entire Long Term Procurement Plan Rulemaking. The final two sub-sections describe Long Term System Security initiatives that are closely inter-related with the CPUC's LTPP Rulemaking but are led by the ISO.

The nature of the Long Term Resource Adequacy Framework will depend critically on the outcome of the CPUC's decision regarding this initiative. For example, if the CPUC decides to adopt a Centralized Capacity Market (CCM) with a primary auction 4-5 years forward of the delivery year, the ISO would expect to conduct a stakeholder process to develop the details of the CCM design and associated tariff provisions. Alternatively, if the CPUC decides to retain today's purely bilateral RA procurement framework, the ISO would need to develop a permanent backstop capacity procurement mechanism.

With the start-up of MRTU, the ISO will implement the Interim Capacity Pricing Mechanism (ICPM) to be used as a backstop capacity procurement device. The ICPM will allow the ISO to backstop or supplement the RA procurement of LSEs if necessary to ensure that there is sufficient generation capacity available to the ISO operators to maintain reliable grid operations. The ICPM is scheduled to sunset on December 31, 2010, at which time another backstop capacity mechanism will be needed as a replacement.

On December 15 2006, the CPUC issued a scoping memorandum that stated that the question of whether to implement a Capacity Market as a central element of its LTRA framework would be included in this proceeding, and a decision on this was scheduled for May, 2008. Most recently the May, 2008 decision has been deferred to an as-yet unspecified date.

The CPUC staff published its "Staff Recommendations on Capacity Market Structure: A Report on the August 2007 Workshops in Collaboration with the ISO" on January 18, 2008. Comments were filed in February 2008 and Reply Comments were submitted in March, 2008. In its comments the ISO recommended a Central Capacity market with a multi-year forward assessment of capacity needs (to be performed collaboratively by CPUC, CEC and ISO), a multi-year forward primary auction, followed by periodic reconfiguration auctions leading up to each delivery year. All Information related to the Long Term Resource Adequacy proceeding can be found on the ISO website at the following link:

http://caiso.com/1b7f/1b7fd6ebe740.html

Ultimately the ISO will need to conduct a stakeholder process which would, at a minimum, develop the replacement for the ICPM when the ICPM sunsets. The specifics of the design of that replacement will of course depend to a large degree on the outcome of the CPUC's decision on the LTRA framework.

8.1 Enhancements to Standard RA Capacity Product (D)

Based on the 2008 Market Initiatives Roadmap process the ISO and stakeholders developed a tariff amendment to implement a standard RA capacity product (SCP) for implementation in the 2010 RA compliance year. This tariff amendment has been substantially approved by FERC and was also included in the CPUC's RA Phase 2 proceeding. In an effort to meet the 2010 compliance year timeframe, some enhancements to the SCP were set aside for future consideration, including generation types that were deferred from the availability metric.

In their comments NRG notes that the ISO has been directed by FERC to work with stakeholders to implement SCP for the deferred types of generation. They also suggest that the ISO should start a stakeholder initiative to consider whether the market is "sufficiently robust enough to warrant the elimination of the exemption from participation in the energy market" by certain classes of generation.

8.2 Successor to the Interim Capacity Procurement Mechanism (ICPM) (F, N)

The ISO is under FERC directive to create a backstop provision that will go into effect upon expiration of ICPM. A long term solution will need to be developed.

8.3 Procedure to Apply Resource Adequacy Must Offer Obligation for a Subset of Hours (D)

Currently, resources that supply Resource Adequacy capacity and are subject to the RA Must Offer Obligation (RA-MOO) are subject to that obligation 24 hours per day, seven days per week. A key impact of this designation is that the resource must submit bids to the ISO markets for the full amount of its RA capacity in all hours, except when it has submitted an outage notification to the ISO through the SLIC system. If the resource does not comply with this requirement, the ISO market systems automatically insert generated bids for the RA capacity that was not offered in a submitted bid. This initiative would develop provisions in the ISO market systems to designate an RA resource as subject to the RA-MOO for only a subset of hours, so that the resource would be required to bid only in those hours and the ISO systems would insert generated bids, if necessary, only in those hours.

9. Seams and Regional Issues

This topic area includes initiatives to improve coordination between the ISO and neighboring control areas, expand markets for import and export of energy and capacity, and support the continuing development of effective energy markets across the western region.

These issues can be tied to the 2009Five-Year Strategic Plan Update under Sub-Objective 2.2 Develop Well Functioning and Transparent Electricity Markets under section 2.2.C entitled "Establish regional presence and enhance planning coordination (2009-2013)."

Deleted: <#>CPUC Long Term Procurement Plan Rulemaking (I)¶
The CPUC Long-Term Procurement Plan (LTPP) proceeding is an umbrella proceeding that integrates all CPUC procurement policies and related programs. As such, it encompasses or accounts for, among other elements, 33% Renewable Portfolio Standard (RPS) requirements, including transmission to access renewables, the Once Through Cooling (OTC) proceeding, climate change, Planning Reserve Margin (PRM), Resource Adequacy (RA), Demand Response (DR), and energy efficiency. ¶
¶
CPUC is moving the LTPP from what was initially essentially a needs based inventory of utility procurement decisions into an integrated resource planning (IRP) framework. The current LTPP proceeding for 2008-2010 is focused on addressing inconsistencies, shortcomings and gaps in the prior (2006/07) round of IOU LTPPs, as well as updating procedures to reflect State legislative or policy objectives that have emerged since then (such as 33% RPS). Core objectives include further standardization of IRP practices and development of methods to reflect uncertainties in compliance costs associated with GHG regulations. The CPUC also wants better information and planning on how the IOUs will achieve the 33% RPS, including transmission needs and integration costs. These results will then inform the next LTPP cycle beginning in 2010, when IOUs will have to file their next round of plans. ¶
Consistent with previous ISO Board directives, the ISO is supporting the CPUC in this Rulemaking to ensure that the objectives and outcomes of the various phases are aligned and an appropriate mix of resources is procured, in the right geographic areas, in adequate amounts to operate the grid reliably. The ISO is expected to take an active role in the review of these plans to provide insight as to their ability to provide the necessary portfolio of resources that can reliably serve the load in the ISO control area. ¶

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9.1 Interchange Transactions after the Real Time Market (D)

This item will explore ways to allow Scheduling Coordinators to schedule bilateral import and export transactions with the ISO after the close of the real time market at T-75 minutes, in situations where the needed import and export transmission capacity is available.

2008 Rank: Medium

9.2 Allocation of Intertie Capacity (D)

To address how intertie capacity gets allocated as well as potentially provide more flexibility to how intertie scheduled cuts get allocated, this initiative would consider other means to allocate intertie (scheduling) capacity. One approach to consider is to allocate capacity via OASIS approach separate from the market. Then only if allocated capacity would a participant be able to offer into the market. How pro-rata cuts are made to those allocated intertie capacity could also be considered in this initiative to provide more flexibility for participants to self-manage what individual schedules would be affected as a result of a Real-Time intertie capacity reduction.

9.3 Dynamic Scheduling/Pseudo Ties (Import and Export) for Load and Generation (N)

Increasingly, dynamic scheduling and pseudo-tie scheduling arrangements are being proposed and implemented for renewables as well as conventional generation. As different versions of these arrangements are proposed, the impact to the market design needs to be evaluated and recommendations made regarding the implementation of such arrangements.

A dynamic intertie schedule is one that can be dispatched by the ISO on the same 5-minute intervals that apply to generation within the ISO control area, or that have specific arrangements between control areas for other forms of sub-hourly dispatch. In contrast, traditional intertie schedules are hourly schedules, which change between hours using established ramping schedules that are common throughout WECC. As noted in other sections of this document topics have arisen that involve changes in intertie schedules at intervals that are more frequent than traditional hourly interchange schedules.

Pseudo ties are a form of dynamic scheduling. Through Pseudo Tie functionality, the ISO is able to attain control of resources external to its operational jurisdiction for the procurement of its Balancing Authority Area services, including the ability to engage in dynamic transfers of Energy and Ancillary Services, and full participation in the Locational Marginal Pricing-based (LMP) markets. Pseudo ties are currently being conducted only as pilot programs to provide practical experience and aid in the development of formal policy standards and tariff provisions. Tariff provisions need to be developed for both pseudo tie import and export to standardize this service.

Status: In the previous version of the catalogue, this initiative was located in the "Completed" section. Although the ISO filed a proforma contract for Resource Specific Systems Resources which was approved by FERC in September, 2008, there has been considerable interest with regard to implementing additional dynamic scheduling/pseudo tie projects related to both conventional and intermittent resources. This ISO will begin a stakeholder process later this year to determine the market design changes and tariff amendments that are required to implement these features.

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Deleted: <#>Import and Export of Ancillary Services (D)¶
This item will consider ways to expand the ability to import and export reserves, and to clearly define the relationship between energy schedules on interties and the associated ancillary service requirements.¶
SCE suggests that interruptible imports bidding into the ISO market should be charged for the additional Operating Reserve. SCE comments that "…prior to allowing non-firm import sales in any future Release, the ISO must, at a minimum, have systems in place, which charge the non-firm imports for their associated AS." (See SCE Comments on Market Initiatives, July 28, 2006, at: ¶
http://www.caiso.com/1845/18459b7a4f300.pdf)¶
Additional aspects of this issue are raised by a requirement in the MRTU design that was stated in FERC's 9/21/2006 decision to conditionally approve the MRTU tariff. This requirement is that export schedules that are not supported by RA resources should have equal scheduling priority as demand within the ISO control area, and the ISO has implemented this requirement in MRTU. In doing so, the ISO has recognized additional issues, including whether the requirement for the non-RA resources to bid into the ISO market should extend past the day ahead market, and whether there should also be an obligation to offer ancillary service bids. Alternatively, a scheduling option for a "unit contingent" exports could resolve questions about ancillary service requirements for these high-priority exports.¶
The ISO will provide a preliminary issue paper to further define these issues. ¶
2008 Rank: Medium¶
Status: There are three separate issues addressed in this initiati ... [3]

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Deleted: <#>Maximizing Intertie Transfer Capability (D)¶
BPA identifies this issue as a way to enhance reliability, market competitiveness, and system efficiency: "Highest priority should be coordination of ATC calculations, outages, and curtailments to maintain transfer capability. Creating ... [4]

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10. Other

10.1 Forward Energy Products (D)

The ISO should consider offering forward energy products, similar to the PX Block Forward. This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2008 Rank: Low

10.2 Sequential Physical Trading Capability (D)

Buyers who receive physical Scheduling Coordinator trades from generation suppliers in the day ahead market should have the ability to trade back the energy to sellers or other eligible Scheduling Coordinators in the Hour Ahead Scheduling Process (HASP) or in the real time (RT) market. Currently the Tariff and new market allows for only financial trades back to the HASP/RT markets.
This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments
2008 Rank: Medium

10.3 Pumped Storage Generation Plant Modeling

In its comment PG&E suggested that the catalogue contain an initiative devoted to the proper modeling of pumped storage units. This will impact not only their Helms units, but other market participants who use, or are considering the use of, this type of generation.

11. Initiatives from 2008 Catalogue that are no longer active

This section provides a list of the 2008 initiatives that have either been completed or inactivated from the market design Initiatives catalogue.

11.1 Completed Initiatives

11.1.1 Operating Reserve Procurement

This initiative was originally identified to evaluate the pre-MRTU impacts of proposed new WECC operating reserve policy. WECC's process of considering changes to how operating reserve should be calculated with regard to each type of interchange schedule (firm, non-firm, unit-contingent) is ongoing at this time. As this effort progresses, the ISO will determine its requirements under new standards that may be adopted.

Status: WECC business practices have been clarified as to how operating reserve should be calculated with regard to each type of interchange schedule and the ISO has implemented the resulting changes in its interchange scheduling practices. The tagging is described in Section 4.2.7 of the Market Operations BPM.

11.1.2 Application of Methodology for Competitive Path Assessment

Local Market Power Mitigation (LMPM) and Reliability Requirements Determination (RRD) functions in MRTU require prior designation of competitive and non-competitive paths in the full network model (FNM).

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In Spring 2005 in the context of the MRTU stakeholder process the California Energy Commission (CEC) proposed a method for reducing the impact of LMP-based marginal transmission loss charges on intermittent resources. At the time the ISO and the stakeholders agreed to defer discussion of this proposal for consideration after MRTU launch. Subsequently, in the 2005 MRTU stakeholder and policy resolution process the ISO agreed to modify the crediting back of marginal loss surplus revenues and accelerate that process, so the question here is whether special treatment for intermittent resources is still needed, and if so, how. FERC's 9/21/06 MRTU Order directs the ISO to address issues related to the integration of intermittent resource issues, including transmission line loss over collection issues, in a future MAP Release. ¶
2008 Rank: Medium¶

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Status: In February of 2009, The Department of Market Monitoring published "Competitive Path Assessment for MRTU, Final Results for MRTU Go-Live" which provided the final path designations. Beginning in year two, the ISO will perform seasonal designations.

11.1.3 Station Power Initiative

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Station power is the energy used to operate auxiliary equipment and other load that is directly related to the production of energy by a generating unit (e.g., heating and lighting for offices located at the plant). FERC has established a policy that allows a single entity that owns one or more generating units to self-supply station power over a monthly netting period using energy generated on-site or remotely.

Status: The Station Power Protocol (Appendix I) was updated and incorporated into the ISO Tariff for MRTU to allow bidding and settlement for all Station Power Load at the locational LMP. Documents related to the updates to the existing Station Power Protocol for MRTU are posted at:

http://www.caiso.com/1ca6/1ca675ae64fe0.html

11.1.4 Limits on Start-up/Minimum Load Costs

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SCE comments on the initial Market Initiatives Roadmap identified that the MRTU Tariff is silent regarding what generators can submit under the election of start-up and minimum load costs. SCE requested clarification that market-based minimum load costs are subject to the bid caps in place for energy, and that the ISO cap the allowable market-based start-up costs:

Status: In October, 2007 the ISO submitted a filing to FERC providing limits on Start Up and Minimum Load costs. FERC accepted this filing in June, 2008 but requested modifications to the calculation of the calculation of the proxy cost. The ISO submitted a compliance filing in July of 2008 and also requested clarification on FERC's Order. In February, 2009 FERC provided additional comment and on March 29, 2009 the ISO submitted changed to tariff section 39.6.1.6.1 in compliance with FERC's Order.

11.1.5 Tracking and Reallocation of CRRs as Load Migrates

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Section 36.8.5 of this originally filed MRTU Tariff requires a load serving entity that loses customers through load migration to transfer a proportionate share of its allocated seasonal CRRs to the load serving entity that gained the customers. This originally filed MRTU tariff language did not specify the ISO's role in such transfers beyond maintaining a system for registering CRR transfers, so the ISO's January 29, 2007 compliance filing to implement Long Term CRRs included a proposal for the ISO to manage the transfer of CRRs to reflect such load migration. FERC's July 6, 2007 decision on Long Term CRRs adopted that proposal.

Status: In its November 7, 2008 Order , FERC accepted the ISO's unopposed proposal to postpone the adjustment of Congestion Revenue Rights eligibility due to load migration until after the 2009 allocation process which was completed in December 2008. The remainder of the work to be done on this initiative deals with implementation. The market design elements of load migration have been completed. Please note that section 8.11 "Revise Load Migration Process" will consider further refinements to the current process.

11.1.6 Generation Resources for Meeting Resource Adequacy Requirements

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SCE suggested that a MRTU issue should be the assurance that power from RA units can be dedicated to serve California load during critical periods: "SCE continues to believe this is a crucial issue and deserves immediate attention at the ISO. Again, at least for the manual work-around, this is a Release 1 issue." (See SCE Comments on Market Initiatives, July 28, 2006, at:

http://www.caiso.com/1845/18459b7a4f300.pdf)

FERC's September 21, 2006, decision on the ISO's MRTU tariff (e.g., Paragraphs 116 and 117) established that exports that are supported by RA resources should have a lower scheduling priority than LSEs within the ISO Control Area. FERC's decision also determined that exports that are supported by non-RA capacity should have a scheduling priority equal to LSEs within the ISO Control Area. The ISO is implementing these provisions in MRTU.

Status: This initiative is complete. Tariff sections 40.6.10 and 40.6.11 were amended to address this issue.

11.1.7 New Methodology for Pricing and Settlement of Real-time LAP Load Deviations

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The filed MRTU Tariff (as filed on February 9, 2006) provided for the settlement of real-time Load Aggregation Point (LAP) load deviations (LAP level uninstructed imbalance energy, "UIE") through a combination of an hourly LAP price (Tier 2 UIE price) and an hourly LAP price adjustment (UIE Adjustment). Over-consumption (real-time LAP load in excess of the day-ahead LAP load schedule) would be charged the sum of the LAP price and the LAP price adjustment and under-consumption (real-time LAP load below the day-ahead LAP schedule) would be paid the difference of the LAP price and the LAP price adjustment (Tariff Section 11.5.2).

Some stakeholders (SCE and NCPA) stated concerns about this approach. Moreover, in the stakeholder discussions related to the design of Convergence Bidding it appeared that having two different real-time LAP prices (depending on over- or under-consumption) would not be compatible with the idea of "price convergence" between day-ahead and real-time markets. Further scrutiny, primarily based on input from SCE and NCPA revealed that under some (albeit rare) conditions, the two-price methodology as stated in the Tariff might lead to excessive charges to a single Scheduling Coordinator (SC).

Status: The ISO posted draft tariff language on April 9, 2007, for stakeholder review as part of the ISO's August 3, 2007, compliance filing.

11.1.8 Interim Measures to Address Day Ahead Underscheduling

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In its September 21, 2006 Order FERC directed the ISO to develop and file interim measures that mitigate any potential economic incentive for Load Serving Entities ("LSEs") to underschedule in the day ahead market that may exist prior to implementation of convergence bidding.

This directive was repeated in the April 20 FERC Order Granting in Part and Denying in Part Requests for Clarification and Rehearing ("April 20 Order on Rehearing"). In this subsequent Order, the FERC stated that "these interim measures are not intended to prevent LSEs from taking steps to reduce the costs of serving load. Instead, these interim measures should be designed to prevent uneconomic behavior. More specifically, we expect the interim measures should address the problem of persistent underscheduling in the DAM on occasions when energy prices suggest that it would be economic to buy in the DAM."

Status: As of the Order dated March 26, 2009, FERC accepted the ISO adjusted proposal. The Order which provides additional background is located on the ISO website at:

http://www.caiso.com/237e/237e8aee34320.pdf

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11.1.9 Partial RA Units

Comments by RTO Advisors proposed that some generators and LSEs may want to enter arrangements in which some or all of the capacity is designated for meeting RA requirements for a period of time, and then not designated for meeting RA requirements for other periods of time: "The ISO should study what modifications are required to MRTU to allow these types of arrangements." (See Comments of RTOAdvisors, July 28, 2006 at:

http://www.caiso.com/1845/18459965461b0.pdf)

Status: The topic of partial Resource Adequacy resource is incorporated in tariff section 40.6.6 and the BPM for Reliability Requirements section 6.1.4

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11.1.10 Relax DEC Bidding Activity Rules on Final Day-Ahead Resource Schedules

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Current bidding activity rules in MRTU disallow Real Time Market energy reduction below the Day-Ahead energy schedule at energy prices that are lower than what was bid in and accepted in the Day-Ahead Market. This DEC Bidding rule was designed to prevent the "DEC" game in situations where transmission derates after the close of the Day Ahead Market require re-dispatch of generation in the Real Time Market.

The ISO initiated a stakeholder process in early 2008 to re-examine this DEC Bidding rule. The ISO proposed removing these rules prior to start up of MRTU. The Board of Governors approved this recommendation in May, 2008.

For MAP the ISO has initially proposed no special limits on DEC bids in the Real Time Market, and if a Scheduling Coordinator does not submit any DEC bids associated with its accepted IFM energy schedule, the SC's economic bids that cleared in the Day Ahead Market would automatically flow into the Real Time Market. This is in contrast to current MRTU functionality, which turns accepted Day-Ahead Bids in to "Self-Schedules" used by the Real Time Market. The intended purpose is to promote a more liquid market for DEC bids in the Real Time Market.

Documents related to this effort are posted at:

http://www.caiso.com/1fb1/1fb184c166370.html

Status: Tariff sheets were filed on May 23, 2008 and accepted by FERC on November 26, 2008. The ISO will continue to monitor to for dec bid gaming and will file amended tariff language if needed.

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11.1.11 Issues Related to Constrained Output Generation (COG) Pricing

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The February 2005 LECG report stated that the mechanism proposed for implementation of real-time constrained output generator (COG) pricing could result in the calculation of inappropriately high prices during circumstances in which uneconomic gas turbines are operating as a result of either minimum run time or minimum-down time constraints.

One proposed solution to be considered, which is used in the NYISO markets, is to use the dispatch level of non-COG resources from the previous interval's pricing run as the initial operating point of the non-COG resources in the pricing run for the current interval, rather than using telemetry as basis for the initial operating point of non-COG resources as the MRTU software will do. A significant drawback of this solution is that this change in the pricing run initialization point can result in much greater problems than it solves when non-COG generators are deviating from instructed dispatch levels. Aside from the change to the pricing run initialization change, another potential fix to this issue would be the addition of a run to the real time optimization, though such an effort may not be feasible from an implementation standpoint. A post-market real time price refinement could possibly achieve the same or at least approximate the outcome of an additional RT optimization run, though this would be onerous to implement and might also be undesirable as it would delay price signals. At this time, and given the small number (10 to 15) and aggregate generating capacity (250 to 350 MW) of COG units in the ISO control area, the ISO recommends making no changes to COG pricing under MAP .

The most current Straw Proposal is posted at:

http://www.caiso.com/1f83/1f83e5f2223d0.pdf

Status: After analyzing the issue the ISO determined that because of the complexity of resolving the issue and the small amount of units that were impacted that no change was warranted at this time. This decision had unanimous stakeholder support.

11.1.12 Compensation for Exceptional Dispatch

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Several generators contended that an exceptional dispatch capacity payment should reflect an appropriate measure of capacity compensation.

Status: Proposed mechanisms for Exceptional Dispatch Bid mitigation and supplemental compensation for resources without Resource Adequacy contracts or ICPM designations were filed with FERC on June 27, 2008 and updated in November 2008. In its February 20, 2009 Order, FERC accepted the ISO's proposal with modifications. Market design issues raised in that Order, including a 30 minute operating reserve and market-based procurement of voltage support are discussed above.

11.1.13 Standard RA Capacity Product

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Several parties have urged the ISO to take up the development of a Standard RA Capacity Product to address the limited tradability of RA Capacity between LSEs that exists today due to the extensive variations among such contracts. Currently RA suppliers' performance and availability obligations are enforced through their bilateral agreements with the LSE buyers of RA Capacity, and there is no defined standard for measuring and ensuring that RA capacity is available when called. The advocates of a ISO role in standardizing the RA Capacity Product believe that development of standardized performance requirements and compliance and penalty provisions within the ISO tariff would increase capacity market efficiency (in either centralized or bilateral capacity markets) by creating a more liquid and tradable product.

2008 Rank: High

Status: This initiative was filed with FERC in April, 2009.

11.1.14 Automation of sub-LAP adjustments in step 3 of LAP clearing validation

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As explained in the MRTU Tariff and testimonies, the LAP clearing procedure recommended by LECG and incorporated in MRTU, may under some rare conditions result in unintended inefficiencies. A three-step process was suggested to deal with such rare situations. The third step in this process involves "softening" the constraints imposed by fixed LAP Load Distribution Factors (LDFs) and allowing independent adjustment of nodal loads. A manual process in MRTU will accomplish this step. The issue here is to automate this step in the post MRTU software. This issue will be addressed as part of the Parameter Tuning effort.

Status: This initiative is outdated and no longer applicable. The third step of this procedure was eliminated and the topic was addressed in the November, 2008 Market Parameters FERC filing. Tariff section 31.3.1.3 was modified to accommodate these changes.

11.1.15 Modeling Constraints of Combined Cycle Units

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In MRTU different configurations of a combined cycle unit are modeled collectively as a single resource. The idea here is to model each configuration as a separate resource, and incorporate software capability to ensure changes in configuration during different scheduling and commitment cycles in the course of the optimization process respect all relevant technical and inter-temporal constraints. This approach is of interest to different ISOs, and the ISO will be monitoring the work of other ISOs in implementing enhanced functionality. Recognizing the software constraints the ISO is faced with, FERC's 9/21/06 MRTU Order (Paragraph 573) directs the ISO to continue working with software vendors to develop an application that will accurately detail the constraints of combined cycle units, and to file tariff language for implementation of such improvements no later than three years after the new market launch.

2008 Rank: High

Status: On May 18, the ISO Board of Governors approved the implementation of Multi-Stage Generating Unit Modeling for implementation in the fourth quarter of 2009.

11.1.16 GMC Under MRTU

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Stakeholders and the ISO have agreed on a set of GMC rate structure elements that will allow SaMC programming to begin, while providing a structure by which analysis of impacts can be performed. .

Status: The GMC rates structure has been filed with FERC and approved.

11.1.17 Increased MW Granularity of CRR Tracking

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The ISO's software systems were originally designed to track CRR MW quantities at a level of 0.1 MW. Changes to some of the CRR rules – particularly the rules for CRR transfers to reflect load migration and for disaggregating CRR nominations sourced at Trading Hubs in the location process – have created a need for finer granularity in the CRR tracking system.

Status: This initiative has been completed and implemented

11.1.18 Credit Requirements for CRR Holders

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With the introduction of obligation CRRs in the ISO markets, market participants may obtain negatively valued CRRs which would have financial obligations in the day ahead market. To minimize the risk to all market participants of a payment default by the negatively valued CRR holder, the ISO conducted a stakeholder process leading to the ISO's June 22, 2007 filing to FERC.

Status: This initiative was approved by the Board of Governors and filed with FERC in May, 2008. In its July 29, 2008 Order, FERC approved this filing.

11.1.19 Integrated Balancing Authority Areas (IBAA)

Early in the MRTU design process the ISO recognized the need to incorporate in its Full Network Model (FNM) the details of certain neighboring Balancing Authority Areas (BAAs). The important BAAs to model in the FNM are those in which the power flows on their systems have large impacts on power flows within the ISO Controlled Grid. The ISO determined that in order to accurately and reliably manage congestion on the ISO Controlled Grid under MRTU, the ISO had to accurately model and capture the power flow or network effects of these BAAs in the ISO's MRTU market systems, specifically, to integrate detailed models of these BAAs into the FNM for MRTU. The ISO originally referred to the BAAs whose systems would be modeled in the FNM as Embedded Control Areas and Adjacent Control Areas, but now refers to them as Integrated Balancing Authority Areas or IBAAs.

For the startup of the MRTU markets the ISO will be modeling in the FNM: the Sacramento Municipal Utility District (SMUD), and the Turlock Irrigation District (TID) BAAs as a single IBAA. These two BAAs were identified as the highest priority for IBAA modeling, but they are not the only neighboring BAAs that may need to be incorporated in the FNM to accomplish the fundamental MRTU design objective of accurate day ahead and real time congestion management. The ISO therefore intends to continue the IBAA effort to determine if further enhancements to the FNM need to be achieved.

Status: The SMUD TID IBAA was successfully implemented on April 1, 2009. The ISO intends to develop an evaluation process to determine how enhancements to the FNM will be addressed.

11.1.20 Resource Adequacy Requirements for Non-CPUC Jurisdictional Entities

The ISO in collaboration with the CPUC and other local regulatory authorities is establishing a framework of requirements to ensure supply sufficiency for the control area. The ISO has established appropriate tariff based reliability requirements, which include reporting and offer obligations to ensure comparability for all parties. Currently, the ISO is working with non-CPUC jurisdictional entities to implement the reporting requirements such that these entities are providing the ISO with critical operating information through a standard template. In addition, the ISO is working with all stakeholders to review the study assumptions and methodologies employed to determine the locational capacity needs in the ISO control area. Moving forward, this activity will continue to clarify and refine the obligations and processes that all non-CPUC jurisdictional entities will use in meeting the ISO reliability requirements.

Status: This initiative has been completed. Non-CPUC jurisdictional entities submit reports to the ISO per the Tariff and BPM requirements.

11.1.21 Start Up Energy Considered as Instructed Energy during Dispatch

The MRTU design did not explicitly recognize the time lapse from unit synchronization to operations at its minimum stable operating unit. Any Start Up Energy, i.e., energy produced

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A dynamic intertie schedule is one that can be dispatched by the ISO on the same 5-minute intervals that apply to generation within the ISO control area, or that have specific arrangements between control areas for other forms of sub-hourly dispatch. In contrast, traditional intertie schedules are hourly schedules, which change between hours using established ramping schedules that are common throughout WECC. As noted in other sections of this document topics have arisen that involve changes in intertie schedules at intervals that are more frequent than traditional hourly interchange schedules. ¶
In the April 2004 filing of Amendment 59, footnote #7, the ISO offered the potential for a pilot program. A pilot program provides practical experience and aids in the development of formal policy, standards and Tariff provisions, if deemed appropriate. MRTU supports dynamic imports, as documented in the BPM for Market Operations. MRTU also supports "pseudo ties" for both import and export; this is a variation in which a specific resource, that is located within one control area, is established through contracts as being part of another control area for purposes of control area operations.¶
Status: The ISO filed a proforma contract in August of 2008 for Resource Specific Systems Resources with FERC. It was approved in September, 2008.¶

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during the time interval from synchronization to minimum load, is assumed to be uninstructed deviation. This issue would explore how Start-up Energy might be considered as instructed energy during the dispatch process. Various stakeholders have suggested that some resources may take time to ramp to minimum load, and that better recognition of this start-up ramp would better reflect the imbalance energy needs and reduce uninstructed deviations during resource start-up.

2008 Rank: Low

Status: This initiative is part of the short term enhancements to improve real time performance.

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11.1.22 Import and Export of Ancillary Services

This item will consider ways to expand the ability to import and export reserves, and to clearly define the relationship between energy schedules on interties and the associated ancillary service requirements.

SCE suggests that interruptible imports bidding into the ISO market should be charged for the additional Operating Reserve. SCE comments that "…prior to allowing non-firm import sales in any future Release, the ISO must, at a minimum, have systems in place, which charge the non-firm imports for their associated AS." (See SCE Comments on Market Initiatives, July 28, 2006, at:

http://www.caiso.com/1845/18459b7a4f300.pdf)

Additional aspects of this issue are raised by a requirement in the MRTU design that was stated in FERC's 9/21/2006 decision to conditionally approve the MRTU tariff. This requirement is that export schedules that are not supported by RA resources should have equal scheduling priority as demand within the ISO control area, and the ISO has implemented this requirement in MRTU. In doing so, the ISO has recognized additional issues, including whether the requirement for the non-resource specific RA resources to bid into the ISO market should extend past the day ahead market, and whether there should also be an obligation to offer ancillary service bids. Alternatively, a scheduling option for a "unit contingent" exports could resolve questions about ancillary service requirements for these high-priority exports.

The ISO will provide a preliminary issue paper to further define these issues.

2008 Rank: Medium

Status: There are three separate issues addressed in this initiative. Two of them have been completed.

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1. The concept that interruptible imports bidding the ISO market should be charged for the additional operating reserve - Section 30.5.2.4 of the tariff states that interruptible must be bid in the DA market and can't be increase in subsequent markets. In this way the ISO know where to allocate the charges
2. FERC 9/21/06 Order - The ISO has addressed the requirement that export schedules have equal scheduling priority as demand
3. The last issue is "whether the requirement for the non-resource specific RA resources to bid into the ISO market should extend past the day ahead market, and whether there should also be an obligation to offer ancillary service bids. Alternatively, a scheduling option for a "unit contingent" exports could resolve questions about ancillary service requirements for these high-priority exports." This issue has been resolved by the implementation of the recent RA AS MOO tariff amendment

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11.2 Deleted Initiatives

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11.2.1 A/S Sub-Regional Cost Allocation

Under MRTU, the allocation of A/S costs is based on A/S responsibility of individual Scheduling Coordinators. A system-wide user rate is computed for each service across all regions (resources) and markets (day ahead, HASP, and Real-time) for each hour.

Due to sub-regional procurement, the costs of A/S in some A/S sub-regions could be higher than in other sub-regions due to unbalanced distribution of resources and transmission constraints. Stakeholders have been supportive on changing the current system-wide A/S cost allocation mechanism.

Status: In June, 2008, the Commission denied the request. FERC reiterated that the ISO's procurement of A/S supports the use of the entire ISO control area and, therefore, it is appropriate to allocate the costs associated with this procurement to all load in the ISO control area.

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11.2.2 Expedited Reporting of SC Bidding

To increase marker transparency, the ISO should consider modifying reporting rules for energy and ancillary service bids which are at or near the bidding caps. Repeatedly bidding at or near price caps, e.g., bidding $399.99/MWh when the price cap is $400/MWh, especially if such bids are for only a small fraction of supply, may be a form of hockey stick bidding designed to manipulate market prices and take advantage of temporary supply and demand conditions. Such bidding has been criticized in appellate decisions reviewing oversight of market based rates, and has been the basis for ordering more rapid disclosure of bids when prices hit caps. In the ERCOT system, when prices hit price caps, limits on disclosure, including entities who make such high bids, are removed. Thus, the release of data should be considered as an interrelated mechanism designed along with price caps to shine the sunlight of public scrutiny on sellers who attempt to set the prices at the highest permissible level. According to one report, once ERCOT began reporting suppliers who bid at a $300/MWh price cap level, the number of suppliers bidding at that cap level dropped by more than two-thirds.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

2008 Rank: Medium

Status: The ISO is currently scheduling a stakeholder and design effort related to the release of information.

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11.2.3 Strengthening General Market Power Provisions

The following three issues were raised in stakeholder comments to the *Initial Scoping of Post MRTU Releases* issue paper that is posted on the ISO website as high priority market enhancements for post MRTU implementation.

- There is currently no Ancillary Service mitigation; ISO sub-regional procurement creates market power opportunities.

- There is currently no RUC mitigation; ISO localized procurement creates market power opportunities
- Potential problems such as hockey stick bidding and evading LMPM need to be considered early in MRTU

The Initial Scoping of Post MRTU Releases issue paper is posted on the ISO website at the following link:

http://www.caiso.com/1c33/1c33cea74b0a0.pdf

Status: This discussion does not focus on any market design initiatives at this time. Market Initiatives that arise out of this particular discussion topic will be included in the catalogue.

11.2.4 Payment Acceleration

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SCE and RTO Advisors suggest the on-going effort to reduce the amount of time for settlement reconciliation should be included as a market initiative issue.

Status: This initiative outside of the scope of the Market Design effort.

11.2.5 Default Charge-Back Mechanism

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The current ISO tariff has a charge-back mechanism that mutualises market participant credit defaults amongst only those market participants considered to be creditors. All other ISO's mutualise credit defaults against all market participants based on the absolute volume or notional value of a market participant's purchase and sale transactions over the billing cycle. The ISO should update their tariff to mutualise credit defaults amongst all market participants.

ISO Finance will begin a stakeholder process this summer to address this issue.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments

Status: This initiative outside of the scope of the Market Design effort.

11.2.6 Maximum Unsecured Credit Limits

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Most other ISO's have maximum unsecured credit limits that are significantly lower than those of the ISO. The ISO should reduce the maximum unsecured credit limits available to market participants.

By improving the ISO's payment and credit processes, the ISO will bring their payment and credit processes closer to industry best practices with respect to payment practices and credit risk management, thereby minimizing the credit risk associated with member participation in the ISO markets.

This was added to the catalogue based on comments submitted by a market participant in April 11, 2008 comments.

Status: Effective March 31, 2009 the ISO's maximum unsecured credit limit was reduced from $250 million to $150 million. The ISO intends to further reduce the maximum unsecured credit limit to $50 million with the implementation of Payment Acceleration.

11.2.7 Credit Requirements for Long-Term CRRs

The ISO conducted a stakeholder process in summer 2007 and obtained the ISO Board of Governors' approval for full-term credit coverage for LT-CRRs. The ISO filed this proposal with FERC. FERC instead approved only a one year credit requirement for LT-CRRs finding that "multiplying by ten (or by the remaining number of years in the long-term CRR's term) the auction price of a one-year CRR does not accurately forecast the expected value of a long-term CRR for the duration of its term."[10] Based on this concern, FERC found it was "reasonable under the circumstances to choose lower barriers to entry over the risk of potentially burdensome over-collateralization. In the March 25, 2008 "CRR Credit Policy Enhancement Issue Paper", the ISO discussed its intent to re-file the full-term credit coverage for LT-CRRs with a modified credit requirement calculation formula to include the "one year historical expected value" of the LT-CRR.[11] Per stakeholder comments received on April 8, 2008, most stakeholders support enhancing the credit requirement for LT-CRRs, but believe that the proposal would benefit from additional stakeholder discussion.

Status: Although this issue is directly related to Long-Term CRRs, it is a credit issue rather than a Market Design initiative. As a result, it will be removed from the Catalogue

11.2.8 Renewable Integration

The ISO's Five-Year Strategic Plan identified as a key corporate initiative to support State public policy regarding the development and reliable integration of renewable resources (Sub-Objective 1.0.C "Implement projects to facilitate integration of renewable resources."). In support of that objective, in November, 2007, the ISO published a report entitled, "Integration of Renewable Resources Report, Transmission and Operating Issues and Recommendations For Integrating Renewable Resources on the CAISO Controlled Grid" (Renewable Resources Report or Report). The ISO initiated the study and resulting report to ensure that the operation and design of the transmission grid fully supports California's established standards with respect to the development and integration of renewable resources. A number of important follow-up tasks were identified in the ISO's technical study.

Status: Renewable Integration and its subtopics are incorporated in the Strategic Planning process and does not apply to the Market Design Initiatives Catalogue. Market Initiatives related to Renewable Integration will be included in the catalogue as they arise.

11.2.8.1 Import and Export of Intermittent Resources

Across the western region there are specific locations where intermitted resources such as wind can be operated most productively, but these locations are not necessarily inside the control areas that can fully utilize such generation. Moreover, some areas that may not contain highly productive intermittent resource locations are still subject to renewable portfolio standards. It is necessary, therefore, to develop principles and procedures for importing and exporting the

[10] "Order Conditionally Accepting in Part and Rejecting in Part Tariff Revisions." 120 FERC ¶ 61,192 at P 45 (2007)

[11] The March 25, 2008 CRR Credit Policy Enhancement Issue Paper and stakeholder comments are posted to the CAISO website at http://www.caiso.com/1b8c/1b8cdf25138a0.html

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energy from intermittent resources in a manner that reflects the unique operating characteristics of these resources. This activity spans multiple functions of the ISO and other organizations, including the Renewables Integration discussed in section 3.2, and infrastructure-related initiatives, as well as market initiatives. This activity also includes collaborative work among the western states' and federal agencies' wind sharing initiatives. Because of the variability of intermittent resources, the market-related aspects have overlapping issues with section 2.4.8, "Dynamic Scheduling (Import and Export) for Load and Generation".

11.2.8.2 Rebate of Transmission Loss Over-Collection for Renewable Resources

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In Spring 2005 in the context of the MRTU stakeholder process the California Energy Commission (CEC) proposed a method for reducing the impact of LMP-based marginal transmission loss charges on intermittent resources. At the time the ISO and the stakeholders agreed to defer discussion of this proposal for consideration after MRTU launch. Subsequently, in the 2005 MRTU stakeholder and policy resolution process the ISO agreed to modify the crediting back of marginal loss surplus revenues and accelerate that process, so the question here is whether special treatment for intermittent resources is still needed, and if so, how. FERC's 9/21/06 MRTU Order directs the ISO to address issues related to the integration of intermittent resource issues, including transmission line loss over collection issues, in a future MAP Release.

2008 Rank: Medium

Status: This initiative has been superseded by other renewable integration initiatives.

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11.2.9 Responsiveness to State and Federal Greenhouse Gas (GHG) Policy

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The ISO's 2008-2012 Five-Year Strategic Plan identifies several activities related to California's initiatives under AB32 to mitigate carbon emissions from the electricity sector. Over 2007, ISO, and the Market Surveillance Committee (MSC), undertook a number of events to evaluate the market and reliability implications of GHG policy options. Testimony was provided to the CPUC and CEC on specific issues. In particular, the policy issues associated with determining the appropriate point of regulation for GHG emissions were examined carefully, as different approaches would have significant implications for ISO market and system operations. See, e.g., the MSC Opinion found at

http://www.caiso.com/1c9d/1c9d6f661ba60.pdf

In 2008-09, ISO will continue to provide views on this issue on a consultative basis with state agencies as well as through the MSC. More generally, GHG policy will have a comprehensive impact on ISO markets and planning functions. As such, ISO will develop over 2008 an analysis of how GHG policy – and intersecting State regulatory initiatives, such as RPS and once-through cooling -- impacts the California and Western wholesale electricity markets and the implications for State public policy.

Status: This topic is incorporated in the Strategic Planning process and does not apply to the Market Design Initiatives Catalogue. Market Initiatives related to GHG policy will be included in the catalogue as they arise.

11.2.10 Normalization of Standards of the Sale of RA Transmission and Generation Across Interties

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There are a variety of issues that complicate the import of RA, energy and ancillary services from the Northwest and other adjacent control areas. Some of these issues are the timing of transaction (T-20 vs. T-75), variations in the treatment of firm energy, and the withholding of unused transmission. These problems are the backdrop for the more obvious problems around the import of intermittent resources, the exchange of scheduling Information and intertie transfer capability. This issue involves the ISO taking several steps toward normalizing transactions between control areas. First, a regional definition for characteristics of standard transactions and terms should be sought. Second MRTU design should accommodate those regionally defined transactions. Finally, a general agreement enabling the long term access to and reservation of transmission in the regional context (i.e. across ties) should be found.

Status: This discussion does not focus on any market design initiatives at this time. Market Initiatives that arise out of this particular discussion topic will be included in the catalogue.

11.2.11 Frequency Responsive Reserve (FRR)

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Recently the WECC Compliance Monitoring and Operating Practices Subcommittee (“CMOPS”) proposed the definition of a new Ancillary Service, Frequency Responsive Reserve (“FRR”), which will have one-minute response capability. It has been estimated that 3200 MW of this reserve will be needed in the west, of which 750-800 MW will be needed within the ISO Control Area. If approved ultimately by WECC, the ISO will need to determine the most effective way to procure this service and develop the appropriate procurement mechanism. At the June 2007 WECC Board of Directors meeting, the Board adopted a proposal by the WECC Operations Committee for a regional criterion to provide for Western Interconnection-wide field testing of the FRR concepts, whose intent is data collection and data analysis, and which expires in September 2009 unless it is extended by the Operating Committee.

Status: This discussion does not focus on any specific market design initiatives at this time. Market Initiatives that arise as this effort progresses and requirements are determined, will be included in the catalogue.

11.2.12 Qualifying Facilities (QF) Participation in ISO Markets

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A recent CPUC decision ties utility contract pricing for combined heat and power (CHP) QF facilities to ISO market prices, yet few CHP projects participate directly with the ISO. This initiative will analyze related tariff issues and reach out to the industry to better understand the obstacles to their increased engagement with the ISO and identify next steps (verbiage comes from Five Year Strategic Plan, Initiatives for Sub-Objective 2.3: Alignment with State and Federal Priorities; 2.3.A Collaborate and help develop environmental policy consistent with reliable system operations.

Status: This initiative was incorporated due to its inclusion in the 2008 Five Year Strategic Plan. It will be removed from the catalogue list however as market design initiatives arise from this topic; they will be added to the catalogue.

11.2.13 CPUC Long Term Procurement Plan Rulemaking

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The CPUC Long-Term Procurement Plan (LTPP) proceeding is an umbrella proceeding that integrates all CPUC procurement policies and related programs. As such, it encompasses or accounts for, among other elements, 33% Renewable Portfolio Standard (RPS) requirements, including transmission to access renewables, the Once Through Cooling (OTC) proceeding, climate change, Planning Reserve Margin (PRM), Resource Adequacy (RA), Demand Response (DR), and energy efficiency.

CPUC is moving the LTPP from what was initially essentially a needs based inventory of utility procurement decisions into an integrated resource planning (IRP) framework. The current LTPP proceeding for 2008-2010 is focused on addressing inconsistencies, shortcomings and gaps in the prior (2006/07) round of IOU LTPPs, as well as updating procedures to reflect State legislative or policy objectives that have emerged since then (such as 33% RPS). Core objectives include further standardization of IRP practices and development of methods to reflect uncertainties in compliance costs associated with GHG regulations. The CPUC also wants better information and planning on how the IOUs will achieve the 33% RPS, including transmission needs and integration costs. These results will then inform the next LTPP cycle beginning in 2010, when IOUs will have to file their next round of plans.

Consistent with previous ISO Board directives, the ISO is supporting the CPUC in this Rulemaking to ensure that the objectives and outcomes of the various phases are aligned and an appropriate mix of resources is procured, in the right geographic areas, in adequate amounts to operate the grid reliably. The ISO is expected to take an active role in the review of these plans to provide insight as to their ability to provide the necessary portfolio of resources that can reliably serve the load in the ISO control area.

Status: This discussion does not focus on any market design initiatives at this time. Market Initiatives that arise out of this particular discussion topic will be included in the catalogue.

11.2.14 Dynamic / Pseudo Tie Imports

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Increasingly, dynamic scheduling and pseudo-tie scheduling arrangements are being proposed and implemented. As different versions of these arrangements are proposed, the impact to the market design is evaluated and recommendations made regarding the implementation of such arrangements. In addition, as the new arrangements are implemented, monitoring is performed to ensure the dynamic and pseudo-tie scheduling arrangements are operating as expected. This topic will be discussed further under section 9.4. This issue has been addressed for generators but not for load. If market participants have interest in pursuing this issue further it will be added to the roadmap for consideration and ranking in the future.

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Status: This discussion does not focus on any market design initiatives at this time. Market Initiatives that arise out of this particular discussion topic will be included in the catalogue.

11.2.15 Improve Tagging Procedures and Functionality

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This item will consider methods to better integrate and streamline the process of producing market schedules and tagging such schedules. By eliminating duplicate information that exists in market schedules and tags it may be possible to streamline the control area check-out process and eliminate market schedule and tagging inconsistencies that can have reliability impacts. By using tag information such as the physical source and physical sink it may be possible to expand upon the benefits of the Full Network Model by modeling the flow effects of the interchange schedules.

2008 Rank: Medium

Status: According to the Manager of Scheduling, this is no longer a market design initiative.

11.2.16 Products Needed to Support Renewable Integration

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The significant increase in intermittent renewable resources in the ISO control area may require new products to enable the ISO to reliably operate the transmission grid. The ISO is currently analyzing the operation requirements for the effective integration of renewable resources into the ISO control area. Once these requirements have been identified, the ISO will review what potential market design and product offering changes are necessary to maintain reliable system operations.

Status: This discussion does not focus on any specific market design initiatives at this time. Market Initiatives that arise as this effort progresses and requirements are determined, will be included in the catalogue.

11.2.17 Exchange of Day Ahead Scheduling Information

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The ISO will work with other control areas in the west to establish day-ahead exchange of scheduling information, to allow coordinated day-ahead congestion management and to reduce the magnitude of unscheduled loop flows in real time by capturing a major portion of such flows in the day-ahead process. The ISO is an active participant in the WECC Seams Issues Subcommittee (SIS). Pending the development through SIS of a process for coordinated day ahead congestion management, the ISO is pursuing improvements in its coordination with individual neighboring control areas, through the Interconnected Control Area Operating Agreements that the ISO has with most of these areas. These commitments are stated in the ISO's January 16, 2007, "Post-Technical Conference Comments on Seams Issues of the California Independent System Operator Corporation", which are available at:

http://www.caiso.com/1b69/1b69af1156ac0.pdf

The ISO has added transmission facilities in neighboring control areas to the ISO's network model in cases where the ISO has determined through optimal power flow studies that doing so increases the accuracy of congestion management within the ISO control area, and has also developed software functionality in MRTU for modeling embedded and adjacent control areas for which adequate information is available to the ISO to support these models. The ISO will be issuing white papers describing these features.

Finally, it is notable that the recently adopted NERC standard TOP-005-1, "Operational Reliability Information", establishes requirements for Balancing Authorities and Transmission Operators to provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow them to perform operational reliability assessments and to coordinate reliable operations. As this information exchange, the ISO expects that it will facilitate improvements to the ISO's congestion management. This standard is at:

ftp://www.nerc.com/pub/sys/all_updl/standards/rs/TOP-005-1.pdf

Pending development of WECC-wide mechanisms for coordinating information exchange and congestion management, the ISO is implementing currently-feasible mechanisms for integrating the most critical Balancing Authority Areas into the ISO's markets. Details of this process are available at:

http://www.caiso.com/1f50/1f50ae5b32340.html

2008 Rank: Medium

Status: Although the ISO will continue to work with the WECC and its regional neighbors to advance this initiative, it has been removed from the catalogue because it is not an initiative that the ISO can move forward through its normal stakeholder process

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11.2.18 Maximizing Intertie Transfer Capability

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BPA identifies this issue as a way to enhance reliability, market competitiveness, and system efficiency: "Highest priority should be coordination of ATC calculations, outages, and curtailments to maintain transfer capability. Creating opportunities for secondary marketing of unused capacity is another priority, including using any available intertie rights (not just PTO rights) to reach ISO markets and participants."

BPA's comments are located at:

http://www.caiso.com/1845/184597e041d00.htm

Status: The ISO will continue to participate in standard setting activities with NERC and is required to comply with NERC standard once they are developed. This is an ongoing effort and not a market design initiative.

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Flexible Term Lengths of Long Term CRRs (D)

FERC's July 6, 2007 Order on CRRs encourages the ISO to consider future flexibility to allow: (i) Long Term CRRs in excess of 10 years, or (ii) annual CRRs with guaranteed renewal rights up to year 10, or (iii) Long Term CRRs with terms ranging from 2 to 9 years. FERC notes that any subsequent change in the available term lengths would have to respect the rights of the holders of any outstanding 10-year CRRs.

2008 Rank: Low

Multi-period Optimization Algorithm for Long Term CRRs (D)

When the ISO performs the initial release of Long Term CRRs for the period 2008-2017, the Simultaneous Feasibility Test (SFT) optimization will treat the entire 10-year time horizon as a single time period (for each combination of Season and Time of Use period) with respect to network model assumptions. The ISO has recognized that a multi-period algorithm can result in a more optimal allocation of Long Term CRRs because it would be able to reflect different assumptions for each year regarding the availability of grid capacity for CRRs, in particular the known expiration of previously released Long Term CRRs, Existing Transmission Contracts and Converted Rights. FERC's July 6 Order affirms that if the ISO and its stakeholders choose to implement the multi-period algorithm, the ISO must make a compliance filing within 30 days explaining the reasons for the change, how the change will affect Long Term CRR nominations, and how the change has been tested. The ISO had planned to develop this functionality in time for the CRR Year Two release process, but is now deferring implementation of this feature beyond CRR Year 2.

2008 Rank: Low

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Import and Export of Ancillary Services (D)

This item will consider ways to expand the ability to import and export reserves, and to clearly define the relationship between energy schedules on interties and the associated ancillary service requirements.

SCE suggests that interruptible imports bidding into the ISO market should be charged for the additional Operating Reserve. SCE comments that "…prior to allowing non-firm import sales in any future Release, the ISO must, at a minimum, have systems in place, which charge the non-firm imports for their associated AS." (See SCE Comments on Market Initiatives, July 28, 2006, at:

http://www.caiso.com/1845/18459b7a4f300.pdf)

Additional aspects of this issue are raised by a requirement in the MRTU design that was stated in FERC's 9/21/2006 decision to conditionally approve the MRTU tariff. This requirement is that export schedules that are not supported by RA resources should have equal scheduling priority as demand within the ISO control area, and the ISO has implemented this requirement in MRTU. In doing so, the ISO has recognized additional issues, including whether the requirement for the non-RA resources to bid into the ISO market should extend past the day ahead market, and whether there should also be an obligation to offer ancillary service bids. Alternatively, a scheduling option for a “unit contingent” exports could resolve questions about ancillary service requirements for these high-priority exports.

The ISO will provide a preliminary issue paper to further define these issues.

2008 Rank: Medium

Status: There are three separate issues addressed in this initiative. Two of them have been completed.

The concept that interruptible imports bidding the ISO market should be charged for the additional operating reserve - Section 30.5.2.4 of the tariff states that interruptible must be bid in the DA market and can't be increase in subsequent markets. In this way the ISO know where to allocate the charges

FERC 9/21/06 Order - The ISO has addressed the requirement that export schedules have equal scheduling priority as demand

The last issue "whether the requirement for the non-RA resources to bid into the ISO market should extend past the day ahead market, and whether there should also be an obligation to offer ancillary service bids. Alternatively, a scheduling option for a “unit contingent” exports could resolve questions about ancillary service requirements for these high-priority exports." is still outstanding.

Exchange of Day Ahead Scheduling Information (D)

The ISO will work with other control areas in the west to establish day-ahead exchange of scheduling information, to allow coordinated day-ahead congestion management and to reduce the magnitude of unscheduled loop flows in real time by capturing a major portion of such flows in the day-ahead process. The ISO is an active participant in the WECC Seams Issues Subcommittee (SIS). Pending the development through SIS of a process for coordinated day ahead congestion management, the ISO is pursuing improvements in its coordination with individual neighboring control areas, through the Interconnected Control Area Operating Agreements that the ISO has with most of these areas. These commitments are stated in the ISO’s January 16, 2007, “Post-Technical Conference Comments on Seams Issues of the California Independent System Operator Corporation”, which are available at:

http://www.caiso.com/1b69/1b69af1156ac0.pdf

The ISO has added transmission facilities in neighboring control areas to the ISO’s network model in cases where the ISO has determined through optimal power flow studies that doing so increases the accuracy of congestion management within the ISO control area, and has also developed software functionality in MRTU for modeling embedded and adjacent control areas for which adequate information is available to the ISO to support these models. The ISO will be issuing white papers describing these features.

Finally, it is notable that the recently adopted NERC standard TOP-005-1, “Operational Reliability Information”, establishes requirements for Balancing Authorities and Transmission Operators to provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow them to perform operational reliability assessments and to coordinate reliable operations. As this information exchange, the ISO expects that it will facilitate improvements to the ISO's congestion management. This standard is at:

ftp://www.nerc.com/pub/sys/all_updl/standards/rs/TOP-005-1.pdf

Pending development of WECC-wide mechanisms for coordinating information exchange and congestion management, the ISO is implementing currently-feasible mechanisms for integrating the most critical Balancing Authority Areas into the ISO's markets. Details of this process are available at:

http://www.caiso.com/1f50/1f50ae5b32340.html

(2008 Rank – Medium)

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Maximizing Intertie Transfer Capability (D)

BPA identifies this issue as a way to enhance reliability, market competitiveness, and system efficiency: "Highest priority should be coordination of ATC calculations, outages, and curtailments to maintain transfer capability. Creating opportunities for secondary marketing of unused capacity is another priority, including using any available intertie rights (not just PTO rights) to reach ISO markets and participants."

BPA's comments are located at:

http://www.caiso.com/1845/184597e041d00.htm

The ISO will continue to participate in standard setting activities with NERC and is required to comply with NERC standard once they are developed. This initiative is not considered discretionary and will not be included in the ranking process.