California ISO
Shaping a Renewed Future

California Independent System Operator Corporation

January 29, 2013

Jennifer Gardner
Western Interstate Energy Board
1600 Broadway Suite 1700
Denver, Colorado, 80202

Dear Jennifer:

The California ISO submitted a conceptual proposal to the Western Governors' Association PUC-EIM group on March 29, 2012. This submittal provides additional information on that proposal and also serves as a follow-up to the Tempe, Arizona meeting hosted by the PUC-EIM group in September. Since then, the ISO has devoted a great deal of effort to clarify its proposal. It builds on an existing successful market platform that is scalable and gives participants a simpler and more economical way to enter an EIM.

The PUC-EIM group provided leadership to the west-wide energy imbalance market dialogue since late 2011, and hosted several forums, including the September 13-14 Tempe meeting that drew over 150 industry experts. Also during 2012, the Northwest Power Pool (NWPP) facilitated energy imbalance market discussions among its members. This letter and the attached red-lined version of the PUC-EIM straw proposal provide follow-up information that was requested at the Tempe meeting.

Tempe meeting follow-up

At the September 13-14 Tempe meeting, the ISO was asked to provide additional information in the following 3 areas:

1. a more detailed description of the ISO proposal;
2. a description of how the ISO proposal will work with non-contiguous territory; and
3. information on the market participant costs on the EIM, i.e., for telemetry and metering.

1. ISO Proposal Detail

Accompanying this document is the PUC-EIM straw proposal that the ISO has red-lined to provide more detail. In its earlier submittal, the ISO demonstrated that its proposal offers the same market functions sought in the straw proposal and also offers additional options provided by the ISO real-time market design. This red-line document provides additional description and clarification to the ISO proposal.

2. Non-contiguous operation

The ISO proposal states that its market design and system modeling approach could facilitate participation by a group of balancing authorities that are non-contiguous with the ISO.

This can be accomplished by limiting the transfer of resources between an EIM participant and the ISO, while the optimization would still be performed as part of the same market run. For a non-contiguous territory, the ISO would simply enforce constraints that would prevent transfers between balancing authority areas but still optimize dispatches with the BAs in the non-contiguous group.

3. Costs for EIM participation

The ISO also discussed participant costs, but further definition of those costs is dependent on implementation specifics with each balancing authority. The ISO looks forward to providing more specifics as individual balancing authorities emerge as potential EIM participants. The EIM requires telemetry for managing dispatches and settlement quality metering to settle imbalances. Many balancing authorities already have similar technology in place and use ICCP links with their headquarters for real-time data flows. The ISO would need to evaluate each specific instance together with the prospective balancing authority and participants to determine actual costs. The overall requirements are detailed in the ISO business practice manuals for Direct Telemetry and Metering, and we would expect that existing metering and telemetry would fill many of these requirements. These materials can be found at the following addresses:

http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Direct Telemetry; and
http://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Metering.

Further, the ISO recently launched an initiative named “Expanding Metering and Telemetry Options”, that will evaluate metering and telemetry requirements, and could develop simpler and more cost-effective options for the metering and telemetry requirements.

An additional comparison chart is attached which further outlines functionality existing within the ISO platform that meets and in some cases exceeds the strawproposal requirements

The ISO welcomes feedback and questions from participants. Please direct to eim@caiso.com.

Sincerely,

Donald L Fuller
Director Strategic Alliances

Comparison of ISO proposal with Straw Proposal

Function	**CAISO proposal**	**Straw Proposal**
Specific ISO benefits		
Economical one-time entrance fee	• 3¢ multiplied by the balancing authority's sales volume	• Funding of new organization and facility to operate the EIM
Ongoing fee	• 19¢ per MWh imbalance (based on grid management charge) • Minor bid segment and charges	• Flat monthly fee that would fund the ongoing costs of the new facility and EIM administrator.
Exit fee	• None	• Based on annual allocations identified above.
Scalability	• Adapts to BAs joining when they want • Approximately 7,000 MW of participation needed to start the market	• Dependent on multiple entities jointly funding up-front costs and on-going costs for a period of years.
Ability to work with non-contiguous entities	• Models a non-contiguous entity through constraints at BA boundaries	• Not contemplated in straw proposal
West-wide modeling	• Provides updates to its existing EMS models consistent with the resources and load of specific entities joining.	• Dependent on support from WECC to develop specific modeling required for optimization, dispatch and settlement.
Proposal features		
Forward-looking awareness of	• Market software automatically enforces constraints before	• Ensures balanced portfolios and availability of reserves,

congestion	they approach critical levels, thus minimizing the chances of curtailment of bilateral schedules.	but does not consider anticipated congestion.
Forward-looking dispatch for smooth ramping	• Security-constrained economic dispatch optimizes for 5-minute intervals over a forward-looking, rolling 1-hour time horizon.	• Dispatch horizon limited to a single 5-minute interval.
Enhanced modeling of physical generation characteristics	• Meets the straw proposal and also models environmental factors using daily energy limits, forbidden operating ranges, multi-stage generators, and special hydro modeling.	• Includes specific generation characteristics and constraints
Real-time outages incorporated into market systems	• Incorporates both generation and transmission outages into market systems, and forward looking congestion management	• Outages incorporated into 5-minute market runs.

Energy Imbalance Protocols

~~Revision 0.d~~
~~Current Operating Document~~

Revised to Support CAISO Cost Estimate for PUC-EIM

1/24/2013

MAINTAINED BY

PUBLISHED:
LATEST REVISION:

Revisions

Revision	Date	Description of Modification
0.a	12/16/2011	Draft
0.b	01/03/2012	Modifications based on initial discussions of revisions.
0.c	01/14/2012	Modifications based on discussions with WECC
0.d	02/06/2012	Cleanup of acronymns
CAISO	01/24/2013	Revised to support CAISO Cost Estimate for PUC-EIM

The CAISO has inserted edits in the PUC-EIM straw proposal that was prepared by SPP, to indicate areas of difference in details between these two ISO's detailed market designs. The intent is to show the alignment between the fundamental, substantive concepts of these real-time energy imbalance markets. It should be understood that much of the content of the PUC-EIM straw proposal has been based on the details of SPP's market, and will require detailed discussions with EIM stakeholders to confirm the acceptability of the detailed design to the affected market participants. In addition, some content in the straw proposal will require review to ensure that it is consistent with current NERC and WECC standards and WECC practices. The absence of changes to the straw proposal in these areas indicates that the ISO does not require changes to the straw proposal as drafted by SPP for consideration in the current PUC-EIM process, but does not imply that the ISO has found consistency with the relevant standards' current requirements and business practices for the WECC region.

Table of Contents

Glossary

Note: Some terminology as used in the PUC-EIM Straw Proposal has reflected terms used in the Southwest Power Pool rather than terms in common use in WECC. In order to minimize changes to the PUC-EIM Straw Proposal document, this document has not changed these terms, but the CAISO recommends that the final Business Practice Manual for the EIM should be conformed to WECC terminology. In some instances, acronyms were used in SPP's straw proposal without being listed in this glossary. The terms referenced by these acronyms have been added, but the CAISO cannot provide specific definitions on SPP's behalf.

Aggregate Price Node (APNode)

A collection of Price Nodes (PNode) whose prices are averaged with a defined weighting component to determine an aggregate price.

Automated Reserve Sharing (ARS)

Balancing Authority (BA)

The responsible entity that integrates Resource plans ahead of time, maintains Load-interchange-Resource balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.

Calibration Allocation Factor (CAF)

The percentage used in allocation of Calibration Energy to the profiled (or consumption metered) Load. This percentage is load weighted for profiled and interval Load.

Calibration Energy

Energy representing the difference between Net Area Input and the sum of metered Load for a Settlement Area and Settlement Interval. Losses are considered in the calculation as an adjustment to the data.

Central Prevailing Time (CPT)

Clock time for the season of a year, i.e. Central Standard Time and Central Daylight Time.

Balancing Authority Area

Defined in the Open Access Transmission Tariff.

Counter Party

Defined in the XML Document as Attachment XXX in the Protocols.

Day Ahead Period (DA)

The time period starting at 0700 and ending at 1530 of the day prior to the Operating Day.

Deployment Interval

The interval for which MO issues dispatch instructions for Energy Imbalance Service. The dispatch interval is currently 5 minutes.

Dispatch Instructions

Expressed as the value at the ~~end~~ middle of the Deployment Interval.

Dispute

Defined in the MO Open Access Transmission Tariff.

Distributed Generation

An electrical Resource greater than 1 MW peak capacity which is connected to a distribution system.

Dynamic Schedule

A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control/Area Control Error equation and the integrated value of which is treated as a schedule. Commonly used for "scheduling" jointly owned Resources or remote Load or generation to or from another Balancing Authority Area.

Electrical Node (ENode)

A physical node of the network model where electrical equipment and components are connected.

Emergency

As defined in the LGIA attachment~~, page 262,~~ to the MO OATT.

Energy Imbalance Market (EIM)

EIM is an ancillary service used to compensate for differences between the scheduled and the actual withdrawal of energy or between the scheduled and the actual output of a Resource.

Energy Management System (EMS)

The software system used by MO for the real-time acquisition of operating data and operations.

Energy Schedule

Defined in the Open Access Transmission Tariff.

Flowgate Constraints

The WECC registered constraints that are also found in the UFMP and are eligible for Congestion Management Events to be called for relief.

Generator Shift Factor (GSF)

As defined in the NERC Glossary Terms used in Reliability Standards.

Hour Ahead Period (HA)

The time period following the close of the Day-Ahead Period and ending at ~~the thirty~~ approximately 40 minutes before the Operating Hour.

Intermittent Resource

A Resource powered solely by wind, solar energy, run-of-river hydro or other unpredictable energy source for which a Market Participant cannot reasonably forecast or control the Resource output on an hour ahead basis. MO will determine whether a Resource qualifies as an Intermittent Resource based upon review of the MP's request.

Interval Data (Idata)

End-use customer or wholesale Load data that is measured using an interval data recorder (IDR) with settlement interval granularity.

Locational Imbalance Pricing (LIP)

The calculation of prices for Energy Imbalance Service at Settlement Locations using the state estimator and a security constrained economic dispatch concept. (e.g. The price to provide least-cost incremental unit of energy at that location). LIP is equivalent to the term Locational Marginal Pricing (LMP) that is used by other markets.

Manual Constraints

Those monitored element and contingency combinations that MO enters manually. These also are non-flowgates.

Market Operations System

The real-time systems responsible for the operational aspects of ancillary service offers, deployment, and Locational Imbalance Pricing calculations.

Market Operator (MO)

Market Participants (MP)

Defined in the Open Access Transmission Tariff.

Market Power

The ability to cause prices to deviate from competitive levels by controlling the provision of generating or transmission capacity to the market, whether by "physical" withholding or "economic" withholding.

Megawatt (MW)

A measurement unit of the instantaneous demand for energy.

Metering Agent (MA)

An entity responsible for the acquisition of end-use meter data, application of losses, aggregation of meter data, application of data to Settlement Intervals and transfer of data to MO. This entity can be a traditional utility entity or other competitive entity. The Market Participant registers their Metering Agent(s) with MO.

Meter Participant

A Market Participant or their designated agent that is settled through the MO energy market and is subject to the energy imbalance settlement process.

Metering Parties

All parties, identified in a transmission service agreement, that have a vested interest in the accuracy of the meter data. Typically this would include MO, Balancing Authority Area Operator, Wire Facilities Owner(s), Meter Owner, and Meter Participant.

Meter Settlement Location

Defined in the Open Access Transmission Tariff.

Native Load Schedule

Defined in the Open Access Transmission Tariff.

Native Load and Portfolio Schedule (NLPS)

Net Actual Interchange

The algebraic sum of all energy flowing into or out of a Settlement Area during a Settlement Interval.

Net Scheduled Interchange (NSI)

The algebraic sum of all energy scheduled to flow into or out of a Settlement Area during a Settlement Interval. NSI includes the ramp on a 4 second interval to achieve the Dispatch Instructions at the end of the Deployment Interval.

Node

A specific electrical bus location in the MO EMS transmission model for which a settlement price is calculated.

North American Electric Reliability Council (NERC)

A non-profit organization whose mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure.

Offer Curve

The Supply Curve is a set of price/quantity pairs that represents the offer to provide energy or curtail.

Operating Day (OD)

The daily period beginning at midnight for which transactions within MO are scheduled.

Operating Hour (OH)

A 60 minute period of time during the Operating Day corresponding to a clock hour. This can also be expressed as the Hour Ending.

Operating Reserve – Spinning

Defined in the Open Access Transmission Tariff.

Operating Reserve – Supplemental

Defined in the Open Access Transmission Tariff. This is often referred to as non-spinning reserve.

Pacific Prevailing Time (PPT)

Clock time for the season of a year, i.e. Pacific Standard Time and Pacific Daylight Time.

Pricing Node (PNode)

A pricing point representing the location where Location Imbalance Prices are calculated. Each PNode is associated with one and only one Electrical Node (ENode) establishing the linkage between the commercial model and the physical model.

PNode Constraints

A second type of Manual Constraint in which MO identifies a PNode or set of PNodes along with static shift factors and a limit. The flow on each PNode when multiplied by its shift factor cannot exceed the stated limit when this constraint is activated.

Portal

Internet interface between MO's computer systems related to market operations and settlement and the Market Participant.

Portfolio Schedule

Energy Schedules which are sourced from Market Participant's fleet of commonly dispatched generation and not a specific Resource. The Settlement Location corresponding to the source of the transaction will be the Market Participant's load Settlement Location.

Profile Data (Pdata)

End-use customer Load data that is not measured using an interval data recorder (IDR) with settlement interval granularity. This includes un-metered and consumption metered data.

Real Time Period

The time period following the close of the Hour Ahead Period during which MO or the Balancing Authority Area operator balances the system by deployment of energy from Energy Imbalance Service, Regulation Service, Operating Reserve- Spinning, Operating Reserve- Supplemental.

Regulation Type

See Regulation and Frequency Response Type as defined in the NERC Operating Manual. The market separates Regulation into Up and Down.

Reserve Sharing System (RSS)

Reserve Sharing Group (RSG)

Resources

Assets which are defined within the Market System which inject energy into the transmission grid, or which reduce the withdrawal of energy from the transmission grid, and may be discretely directed by the ~~RTO or ISO~~ MO. These Resources include generation and controllable Load.

Resource/Obligation Type

Defined in the XML Document as Attachment XXX in the Protocols.

Resource Test Mode

Operation of new facilities not yet commercially accepted by the owner of the Resource designed to assist in commercial acceptance of the Resource by the owner or the operation of a Resource that has been off-line due to an extended maintenance period. This operation must be coordinated with the MO Market Operator to the extent possible.

RTCA Constraints

Constraints found to be at risk by the MO Real-Time Contingency Analysis Application that are not defined as flowgates.

Self-Dispatched Resource

A Resource that is not available for dispatch by MO to support Market Operations.

Settlement Area

A geographic area for which transmission interval metering can account for the net area Load. A settlement area is typically a Balancing Authority Area, and must be completely contained in a single Balancing Authority Area

Settlement Interval

The period of time for which the market is financially settled. This period of time is coincident with scheduling granularity and Energy Imbalance Service price calculation intervals. The use of settlement intervals for net interchange between balancing areas, for loads with hourly metering, and for other resources that do not submit bids for dispatch by EIM is ~~currently~~ equivalent to one hour settlements. The settlement interval for resources that elect to submit bids for dispatch by EIM matches the Deployment Interval.*

Settlement Location

Locations defined for the purpose of commercial operations and settlement. A Settlement Location is the location of finest granularity for calculation of Imbalance Settlements. The data required must be at this level of granularity in schedules, meter data, and pricing.

Settlement Statement

A statement of the market and other tariff charges related to the Settlement for a Market Participant.

Shut-down Mode

A period of time after the Resource operates below its Minimum Capacity Operating Limit as indicated in the Resource Plan, but not to exceed one hour before and after the scheduled time for a Resource to be removed from the electrical grid, during which a Resource will be exempt from Uninstructed Deviation Penalties.

MO Region

The geographic area of the Transmission System for which MO is the Transmission Provider.

Start-up Mode

A period of time before the Resource reaches its Minimum Capacity Operating Limit as indicated in the Resource Plan, but not to exceed 2 hours before and after the scheduled time for a Resource to synchronize to the grid, during which a Resource will be exempt from Uninstructed Deviation Penalties.

State Estimator

The computer software used to estimate the properties of the electric system based on a sample of system measurements.

Transaction Distribution Factor (TDF)

As defined in the NERC Glossary of Terms used in Reliability Standards.

Unscheduled Flow Mitigation Procedure (UFMP)

As defined in the WECC Standards.

Watch List Constraints

Constraints found to be loaded at or above their limit during the MOS Hour Ahead Balancing studies and , optionally, Day Ahead Congestion Management studies during the Contingency Analysis phase of those applications that are also not defined as flowgates.

Wire Facilities Owner(s)

Entity that owns transmission or distribution system infrastructure.

1 Introduction

The MO Energy Imbalance Market Protocol document serves as a companion to the Tariff,

The Market Protocol document specifically defines the terms, procedures, Energy Obligations and responsibilities of the Market Operator (MO), Reliability Coordinator (RC), and Market

Participants (MP) relating to the MO Market functions The Energy Imbalance Market (EIM) has the following major features:

This is an imbalance energy only market and does not supersede any MP's Energy Obligations with respect to any other capacity or ancillary service obligations. The responsibilities in regards to capacity adequacy, reserves, and other reliability-based concerns do not change as a result of this market.

All MPs with Loads and/or Resources will be subject to EIM under this market. All participants must register with the Market. Entities wishing to provide EIM energy will submit offers to the market.

All Loads and Resources are located at Settlement Locations. EIM offers are submitted for each Resource participating in the EIM market. These offers are tied to the Settlement Location at which the Resource is located. MO will use a Security Constrained Economic Dispatch (SCED) to determine the lowest cost increment of energy that can be delivered to each location considering the submitted offers, transmission limitations and system topology. EIM dispatch instructions will be calculated for Dispatchable Resources, and Locational Imbalance Prices (LIP's) will be calculated for each Settlement Location on the system.

Resources will be settled based on the LIP associated with their Settlement Location. Resources are only settled nodally. Load may choose to be settled either zonally or nodally. The LIP's are based on the Resource offers and are locational.

Energy Imbalance Service is calculated by subtracting scheduled MWh from actual MWh. Settlement will be the quantity of EIM energy times the LIP at that Settlement Location ~~for~~ during a given Operating Hour. When scheduled quantities equal actual quantities, EIM energy and settlement are zero. The data used in Market Settlement must be submitted by Settlement Location (node or zone).

This Market will be facilitated such that the MO maintains revenue neutrality. Any difference between charges for EIM and payments will be uplifted (see Settlement Section 4.2).

The general organization of this document is in relation to the timeline.

2 Timeline

2.1 MO Operational Information Exchange

The operation of the market system and EIM market requires the exchange of a variety of information between the systems of the MO and market participants.

The specific timeline and responsibilities for the provision of this information are defined in the sections that follow. Some events listed here are based on the design of the Southwest Power Pool rather than resulting from detailed stakeholder process among EIM participants. In order to minimize changes to the PUC-EIM Straw Proposal document, this document has not changed the timeline of these events, but the CAISO recommends that a stakeholder process among EIM market participants should define the final design.

The timeline for Operating Day EIM Market Activities reflects the CAISO's current proposal for compliance with FERC Order 764.

Day-Ahead Activities		
Timeline	**Market Participant Action**	**Market Operator Action**
0700 of Operating Day-1 (OD-1)		Day prior to operating day
0730 of OD –1		Next Day's Ancillary Service (AS) obligations for each Market Participant and the MO region are sent to the MP via the Portal. For the next 7 days, beginning with the Operating Day the MO will post hourly Load Forecast by Settlement Area and the MO region
1100 of OD –1	Market Participants submit Load Forecasts, Resource Plan and Ancillary Service Plan (see Sections 3 and 4)	
1200 of OD –1		Review Market Participant Ancillary Service Plans and notify applicable Balancing Authority Areas and MP's when they do not balance and/or mismatched.
By 1300 of OD –1	Make necessary updates to Ancillary Service Plans to address deficiencies (mismatched and unbalanced), and revise Resource Plans if needed	

Day-Ahead Activities		
Timeline	**Market Participant Action**	**Market Operator Action**
By 1400 of OD-1		Review Market Participant Ancillary Service Plans and notify applicable Balancing Authority Areas and MP's of deficiencies and of anticipated congestion based on submitted Resource Plans, to allow adjustments to Resource Plans prior to real-time to mitigate congestion. In event of unit contingency the MO operator may update A/S Plans to accommodate the situation.

Operating Day EIM Market Activities		
Timeline	**Market Participant Action**	**Market Operator Action**
OD-7 to OD OH - ~~45~~ 75 minutes (OH is start of operating hour) Changes to self-schedules may be submitted up to 40 minutes before each 15-minute interval, or up to 20 minutes before the interval based on physical availability.[1]	Submit Offer Curves for upcoming hours all or portion of OD. Based on Offers, Resources will be deployed on 5-minute intervals (See Section 5 For Offer Curve details). Submit energy schedules if necessary.	Lock Resource Plans for OH

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[1] At the time of writing, all real-time market bids and self-schedules are received by 75 minutes before the start of an operating hour. This will change with the implementation of intra-hour scheduling in compliance with FERC Order 764, but the associated stakeholder process is still in progress.

30 minutes prior to start of tagged schedules Note: This timing may be affected by WECC entities' compliance filings for FERC Order 764.	Due to the NERC approval guidelines (approval may take 10 minutes), tagged schedules must be submitted at least 30 minutes prior to the start of the tagged schedule. All Energy Schedules must have received approvals at least 20 minutes prior to the start of the tagged schedule.	
20 minutes prior to start of NLS schedules	The process of submitting an NLPS results in automatic approval, due to pre-validation of Designated Network Resources. All Energy Schedules must have received approvals at least 20 minutes prior to the start of the NLPS schedule.	

Operating Hour Activities

Timeline	**Market Participant Action**	**Market Operator Action**
Beginning of Deployment Interval –7.5 minutes		1. Project Load Forecast 2. Accept State Estimator solution 3. Process OH schedules 4. Calculate Security Constrained Economic Dispatch (SCED)
Beginning of Deployment Interval –5 minutes up to Beginning of Deployment Interval -2.5~~1~~ minute (Delivery is upon completion and should be prior to Beginning of Deployment Interval -2.5 minutes)		Send Dispatch Instructions for the ~~end~~ middle of the Deployment Interval (including LIP in the XML message)
Beginning of Deployment Interval -2.5 minutes	Begin ramp to achieve Dispatch Instructions for ~~end~~ middle of Deployment Interval	MO calculated NSI reflects the ramp in 4-second values, including the impact of Congestion Management Events and Automated Reserve Sharing (ARS) events.

Operating Hour Activities		
Timeline	**Market Participant Action**	**Market Operator Action**
~~End~~ Middle of Deployment Interval	Resources at instructed levels	
Beginning of Deployment Interval -2.5 minutes ~~Within OH + 15 minutes~~		LIP for Deployment Interval accessible on the Portal and on www.xxx.org website ~~for limited queries~~.
Within OH + 15 minutes		LIP for hourly Settlement Interval for net interchange available, including Meter Settlement Locations, on the Portal and on www.xxx.org website.
Approximately every 4 seconds		Net Scheduled Interchange (NSI) is modified and sent out to Balancing Authority Area (CA) to support the ramp to achieve the Dispatch Instructions. The NSI accounts for the impacts of Congestion Management Events and ARS events.

Post-Operating Day Activities		
Timeline	**Market Participant Action**	**Market Operator Action**
By ~~4~~ 48 days after the OD	Submit Load, Resource, and interconnection Meter Data	
By ~~5~~ 3 days after the OD		Initial settlement statements by Settlement Location, Hour, and Market Participant
By ~~45~~ 55 days after the OD Additional settlement statements occur between these dates		Final settlement statement by Settlement Location, Hour, and Market Participant

Updates to Operating Day Data		
Timeline	**Market Participant Action**	**Market Operator Action**
Immediately following an RSS event		Assisting Balancing Authority Area Load to Contingent Balancing Authority Area Load schedules are created, in the scheduling system, for each participant involved in the RSS event. One schedule is created from the Contingent Balancing Authority Area Load to the Contingent Resource for the amount lost.
0100 following the OD+3 containing an RSS event	Participants have the opportunity to offset the Load schedules created by the RSS event by entering Resource to Load schedules, reflecting generation Resources actually utilized to assist in the event for use in Settlement.	
0100 following the OD + 3	Estimated Dynamic Schedules may be updated	BA Performs checkouts, including Dynamic Scheduling

3 Resource Plans

3.1 Introduction

The Resource Plan is submitted by Market Participants with registered Resources to enable the MO Market Operation System (MOS) to assess Resource and Ancillary Service adequacy for the market region, each market Balancing Authority Area, and each Market Participant. The operator of the Balancing Authority Area remains responsible for the balance of Load and Resources within the Balancing Authority Area boundary.

3.2 Contents

The Resource Plan covers a seven-day horizon (with hourly detail) beginning with the Operating Day. See MO Criteria Appendix 7 and XML Specifications for additional details. Specifically, the Resource Plan contains entries for each Resource for each hour of the seven day horizon similar to the following:

- Resource ID - Unique identifier for Resource in Market
- Resource Type - GEN-Generation, CLD-Controllable Load, or PLT-Plant
- Planned Megawatts - Anticipated dispatch of unit independent of energy imbalance deployment (This value is within the dispatchable range of the Resource).
- Minimum Capacity Operating Limit - Resource physical minimum sustainable output for each Operating Hour ("MinMW")
- Minimum Economic Capacity Operating Limit - Resource economic minimum output selected by Market Participant for each Operating Hour ("MinEconMW"). Must be equal to or greater than value provided for Minimum Capacity Operating Limit.
- ~~Minimum Emergency Capacity Operating Limit - Resource physical minimum emergency output for each Operating Hour ("MinEmerMW"). Must be equal to or less than value provided for Minimum Capacity Operating Limit.~~
- Maximum Capacity Operating Limit - Resource physical maximum sustainable output for each Operating Hour ("Max MW")
- Maximum Economic Capacity Operating Limit - Resource economic maximum output selected by Market Participant for each Operating Hour ("MaxEconMW"). Must be equal to or less than value provided for Maximum Capacity Operating Limit.
- ~~Maximum Emergency Capacity Operating Limit - Resource physical maximum emergency output for each Operating Hour ("MaxEmerMW"). Must be equal to or greater than value provided for Maximum Capacity Operating Limit.~~
- Ramp Rate - Rate at which Resource can change output in MW/min

Market Participants will submit their Ramp Rates through a segmented profile. The profile will require at least 1 segment and may have up to *n* segments where *n* will be defined by Market Operator (MO), ~~initially~~ currently set to ~~10~~ 2. For Multi-Stage Generating Resources (e.g., combined cycle generation), this number applies separately to each resource configuration. For example, a combined cycle generator with four configurations may have 8 ramp rate segments in total.

  - Breakpoint Limit 1– Resource MW output at which segment 1 Ramp Rates will apply. If the value is not less or equal to actual measured MW during deployment, the values in segment 1 will apply back to the actual measured MW.
  - Block 1 Rate ~~Up~~ – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

  - ~~Block 1 Rate Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1.~~
  - ~~Block 1 Rate Emergency – Rate at which Resource can change output upward or downward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an emergency.~~
  - Breakpoint Limit *n*– Resource MW output at which Ramp Rate changes from previous segment values to segment *n* values.
  - Block *n* Rate~~Up~~ - Rate at which Resource can change output upward in MW/min at output levels greater than or equal to the Breakpoint Limit *n*
  - ~~Block *n* Rate Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to the Breakpoint Limit *n*~~
  - ~~Block *n* Rate Emergency – Rate at which Resource can change output upward or downward in MW/min at output levels greater than the Breakpoint Limit 1 and less than Breakpoint Limit 2 during an emergency.~~

- Resource Status: Resources are considered self-committed in a particular hour if they submit a self-schedule for energy greater than zero. To the extent that resources have characteristics that do not vary from day to day (e.g., being quick-start, being variable energy resources that cannot be dispatched, or serving cogeneration), the ISO records these characteristics in its master file, and it is not necessary to submit these characteristics in market bids. If a resource is unavailable due to an outage or derates, the ISO's outage tracking system provides more detailed information than could be provided in market bids. The ISO's market system automatically and continuously tracks resources' status such as being on-line or off-line, in startup or shutdown processes, or being subject to minimum run times or off-line times, as well as other limits including maximum starts per day and daily energy limitations.
  - ~~Available – Resource is online and available for MO Deployment.~~
  - ~~Available Quick Start – Resource is off line, available for MO deployment, capable of closing the breaker, synchronizing to the grid, and reaching the operating level consistent with the dispatch instruction.~~
  - ~~Unavailable – Resource is offline and unavailable for MO Deployment or other uses.~~
  - ~~Supplemental – Resource is offline and available for satisfying Supplemental Reserve requirements. The Resource will NOT be dispatched by the MOS system.~~
  - ~~Self-dispatched – Resource is online and unavailable for MO Deployment.~~

- ~~Intermittent – Resource is online and unable to follow Dispatch Instructions due to the uncontrollable nature of the Resource output. Resource must be registered with MO as intermittent in order to use this status.~~

- ~~Startup/Shutdown – Resource is online and unable to follow Dispatch Instructions due to either beginning or ending Resource operation~~

- ~~Testing – Resource is online and unable to follow Dispatch Instructions due to uncontrollable Resource output resulting from unit testing. A Resource must coordinate with and otherwise inform the MO Reliability Desk of testing plans in order to use this status.~~

- ~~Qualified Cogeneration — Resource is online and unable to follow Dispatch Instructions. To use this status a Resource must be FERC certified as a qualifying cogeneration facility, and be delivering their output pursuant to the obligation to purchase under PURPA.~~

- ~~Exigent Conditions – Resource is online and unable to follow Dispatch Instructions due to sudden changes in Resource conditions or operating characteristics that prevent predictable Resource operation. This status will only be available via an Market Operator override. This override status is available for up to six consecutive hours which may be extended based on the operating conditions discussed with the Market Participant. The Market Participant is required to notify when this override condition should be lifted or extended beyond the initial period or subsequent periods.~~

  ~~Resources in Testing, or Startup/Shutdown status will be permitted to report Ancillary Services if the limitations on their ability to follow Dispatch Instructions or adhere to their Schedules do not preclude them from providing said Ancillary Services~~

Note that the meaning and format and current required fields of this submission are fully defined in the XML Specification document.

3.3 Timing and Submission Mechanisms

Market Participants with registered Resources will be required to submit Resource Plans and are required to keep the plan up to date throughout the Operating Day. The first submission of Resource Plans for an Operating Day and beyond is by 1100 the day preceding the Operating Day. This data for any individual hour may be updated until 45 minutes prior to the beginning of that Operating Hour.

This data will be submitted via the Portal or the Application Program Interface (API).

3.4 Use of Data

The Market Operator will utilize the Planned Megawatts to assist with determining whether a Resource is in Start-Up Mode or Shut-Down Mode. The Market Operator will utilize Resource Plan data along with the Offer Curves, Load Forecasts, and the State Estimator to determine the Dispatch Instruction for EIM Resources. If a Resource is on and unavailable, to the Market, it is considered a Self-dispatched Resource and will only be dispatched by MO or BA (when MO is notified) in a system emergency (of type "out of merit energy" or "OOME" dispatch instruction).

3.5 MO Manual Overrides

Market Participants are required to keep the data up-to-date during the Operating Day. In the event of a required change in the Resource Plan due to physical Resource changes during an Operating Hour, the Market Participant is responsible for notifying Market Operator of required changes, and the Market Operator will make the required modification for the current Operating Hour. Customers shall remain responsible for accurately reflecting Resources in their Resource plan submissions for subsequent hours.

3.6 Load Forecast

Market Operator uses Load forecast information for the following EIM Market purposes:

- Determine amount of Resources necessary to be dispatched by the market
- Estimate the amount of Market Flow on flowgates for next-hour
- Perform simultaneous feasibility studies
- Determine supply adequacy

3.6.1 Market Participant Load Forecasting

The Market Participant Load forecast for Resource planning purposes shall be submitted as specified herein. By 11:00 a.m. PPT on the day prior to the operating day, each Market Participant that has registered a load Settlement Location shall submit to MO the amount of Load it expects to serve by Settlement Area for each hour of the next Operating Day. The Market Participant may update its forecast for any Operating Hour as late as 45 minutes prior to that Operating Hour. This information shall be submitted via the Portal or Application Program Interface (API). The Load Forecasts provided by the Market Participants shall be used by the Market Operator to evaluate Market Participants' Resource Plans and to compare with Load forecasts submitted by Balancing Authorities pursuant MO those Settlement Area forecasts developed by MO . The Market Participants' Load forecast should be net of "behind-the-meter" generation that is not registered as a Resource. When a registered Resource is electrically located behind a load settlement location meter the total load will be calculated by summing the load meter and the generator meter.

Market Operator will use the Load forecasts submitted by the Market Participants as described above in conjunction with those Market Participants' Resource Plans and schedules to determine if each Market Participant has committed sufficient capacity to supply its Energy Obligations.

To ensure that the Market Participant load forecasts are reasonable for this purpose, MO will aggregate the Load forecasts submitted by Market Participants by Settlement Area and compare to the Settlement Area forecast developed by MO , as discussed in Section 3.6.2, and to the Balancing Authority Area Load forecast submitted by the Balancing Authority. Market Operator will investigate and analyze where significant differences exist.

3.6.2 MO Load Forecast

Short-term and mid-term Settlement Area forecasts are developed by MO . The short-term forecast produces a value every 5 minutes for the next 15 minutes. The mid-term forecast produces hourly values for the next hour through 7 days out. MO aggregates its Settlement Area short-term Load forecasts along with schedules into and out of the market footprint to determine the amount of Resources to be dispatched by the market for the upcoming dispatch cycle. The mid-term forecast is an input used to estimate the amount of Market Flow on flowgates for the next-hour and to perform simultaneous feasibility studies. To ensure that MO's forecasts are reasonable for these purposes, MO will compare its Settlement Area forecasts with the Load forecasts submitted by Balancing Authorities. If MO's Load forecast for a particular Settlement Area appears to be consistently inferior to the associated Balancing Authority's Load forecast or if MO's Load forecasting engine fails to produce a forecast, the Balancing Authority forecast will be used.

4 Ancillary Service Plan

4.1 Introduction

Each MP submits its Ancillary Service Plan to enable the Market Operation System to confirm each MP is satisfying its Ancillary Service obligations. The Ancillary Service Plan indicates transfers of Energy Obligations between MPs and, when self-provided, which Resources are providing these services.

MP's must indicate on the AS Plan Reserves and Regulation (Spin, Supp, Upreg, Downreg) sufficient to meet their Energy Obligations. MP's may also designate Reserves and Regulation in excess of their Energy Obligations for reliability purposes.

4.2 Contents

Resources will submit Ancillary Service Plans identifying designations similar to the following:

- Operating Day
- Operating Hour
- Counter Party
- Counter Party Type (MP, PLT, GEN, CLD, RTO)

- A/S Schedules (Resource or Obligation)
- Megawatts
- Balancing Authority Area
- Regulation Reserve Type – Up/Down
- Operating Reserve – Spinning
- Operating Reserve – Supplemental

MP's with Loads will submit Ancillary Service Plans identifying the MP's with Resources providing reserves. See XML Specifications for further details. Note that the meaning and format and currently required fields of this submission are fully defined in the XML Specification document.

4.3 Timing and Submission Mechanism

MP's who are required to provide ancillary services, and those who have made arrangements to self-provide in whole or part, are required to submit an Ancillary Service Plan to indicate how it intends to satisfy its ancillary service obligations. An Ancillary Service Plan for each hour of an Operating Day must be submitted no later than 1300 the day prior to the operating day. The Ancillary Service Plan for any individual hour may be updated until 45 minutes prior to the beginning of that Operating Hour. The adequacy and validation of capability to provide the ancillary services will be assessed by MO and any discrepancies will be reported back to the MP to enable modification of the Ancillary Service Plan.

If a Market Participant's Ancillary Service Plan has not resolved a deficiency in meeting its Ancillary Services Obligation prior to the Ancillary Services Plan deadlines (both day prior and operating day) the Market Participant is required to inform WECC and MO how the deficiency will be satisfied.

This data will be submitted via the Portal or the Application Program Interface (API).

4.4 Use of Data

MO will post daily Ancillary Service requirements for each MP and the MO region for the Operating Day. MO will validate MP's Ancillary Service Plans against MO calculations and identify shortages, and coordinate with affected Balancing Authority Areas and WECC. The Ancillary Service Plans will also be used by the Market Operations System to ensure that EIM deployment does not consume unloaded capacity being utilized for other Ancillary Services.

4.4.1 MO Manual Overrides

Market Participants are required to keep the data up-to-date during the Operating Day. In the event of a required change in the Ancillary Service Plan due to physical Resource changes during an Operating Hour, the Market Participant is responsible for notifying MO of required changes, and MO will make the required modification for the current Operating Hour. Customers shall remain responsible for accurately reflecting Resources in their Ancillary Service plan submissions for subsequent hours.

5 Offer Curves

5.1 Introduction

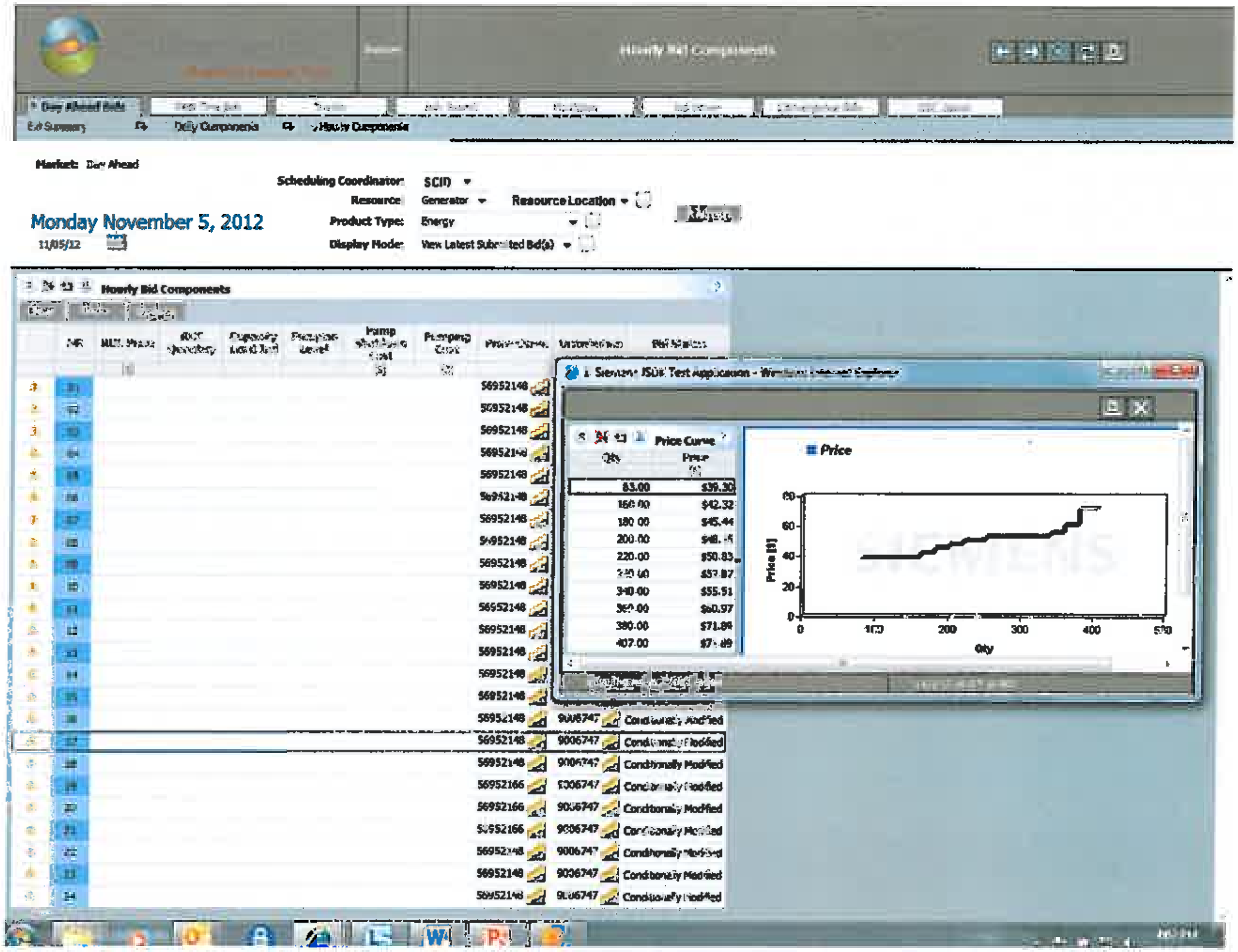
To submit an offer an Market Participant must have executed the service agreement as specified in Tariff Attachment XX. Offer Curves are submitted by Resources. Resources that offer energy into the MO EIM market must specify an offer price. The price is specified using an Offer Curve. The Offer Curve allows Resources to offer multiple points at different prices. An Offer Curve is submitted for each Resource with up to ten monotonically increasing pairs of MWh and price. The price may be positive or negative and is subject to an offer cap and floor. See Section 14.4.2 and 14.4.3 for further details regarding Offer Curve limits. Owners of Joint Owned Units may agree to register the units as separate Resources.

5.2 Contents

For each Resource, the Offer Curve will include the following components:

- Date
- Hour Ending
- Resource
- Megawatts
- Price/MWh

Example of an Offer Curve from the Portal :



Market: Day Ahead

Monday November 5, 2012
11/05/12

Scheduling Coordinator: SCID
Resource: Generator
Resource Location
Product Type: Energy
Display Mode: View Latest Submitted Bid(s)

Price Curve

Qty	Price ($)
83.00	$39.30
160.00	$42.32
180.00	$45.44
200.00	[illegible]
220.00	$50.83
[illegible]	$57.87
340.00	$55.51
[illegible]	$60.97
380.00	$71.89
407.00	[illegible]

5.3 Timing and Submission Mechanism

Offer Curves may be submitted as early as 7 days prior to the Operating Day and may be submitted or revised until 45 minutes prior to the Operating Hour. If a Resource Plan indicates that the Resource is available for MO dispatch and an Offer Curve is not submitted, the most recent Offer Curve will be used for deployment. If an Offer Curve has not been submitted to MOS within the last 7 days, consistent with the MOS data purge timeline, the default price goes to 0 to the Max MW available.

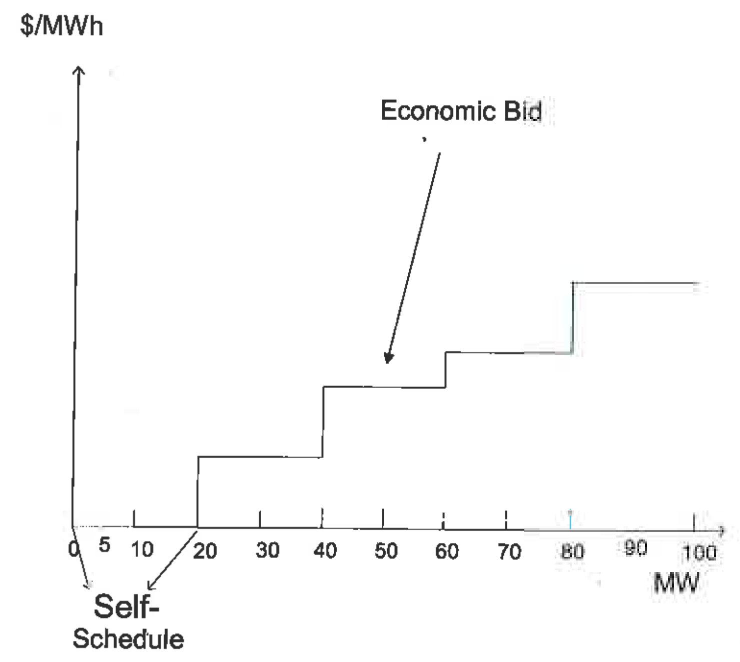
This data will be submitted via the Portal or the Application Program Interface (API) as defined in Appendix B.

5.4 Use of Data

The Offer Curve is used in the calculation necessary for deployment and the resulting Locational Imbalance Price (LIP). The set of Price Points that are submitted are used as the beginning and ending values for ~~calculating a linear slope for each set of beginning and ending~~ bid segments between these values. ~~Therefore, each MW between the two price points has a different price due to the interpolation of the submitted price points.~~ The first Pricing Point must correspond to the ~~zero (0) MW~~ minimum loading level that is offered for dispatch ~~regardless of whether the unit is capable of operating at that level~~. The amount between zero (0) MW and the first Pricing Point is considered to bs a self-schedule, below which the Market Operator may not dispatch the resource. The last Price Point on the Offer Curve is used for all MWs between that point and the Maximum Capacity from the Resource Plan. ~~These examples~~ Example 1 illustrates the Offer Curve used in the deployment calculations that were developed from the submitted price MW pairs, for a typical resource.

Example 1: Typical Offer Curve for Generation Dispatch

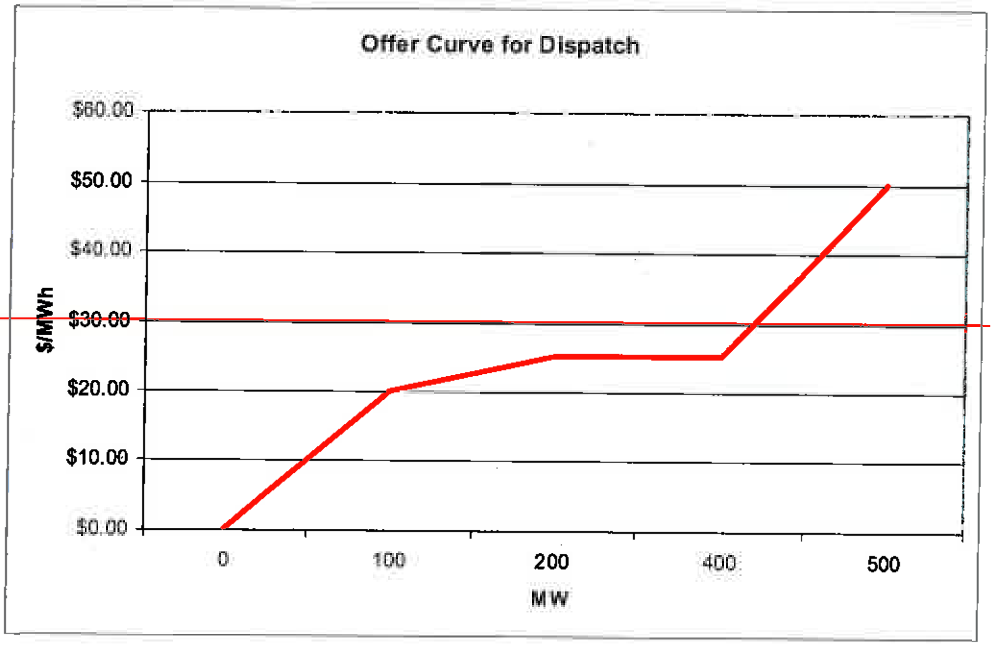
Submitted Data	
MW	$/MWh
20	10
40	20
60	25
80	35
100	35



A generator (e.g., combined cycle) for which the operating costs may vary between different physical configurations may optionally choose to participate as a multi-stage generator. Using this option, the market participant may provide a separate offer curve for each configuration, and inform the Market Operator in which configuration the generator will be operating during each 15-minute interval. For each configuration, the offer curve has the characteristics illustrated in Example 1.

Submitted Data

MW	$
0	$0.00
100	$20.00
200	$25.00
400	$25.01
500	$50.00

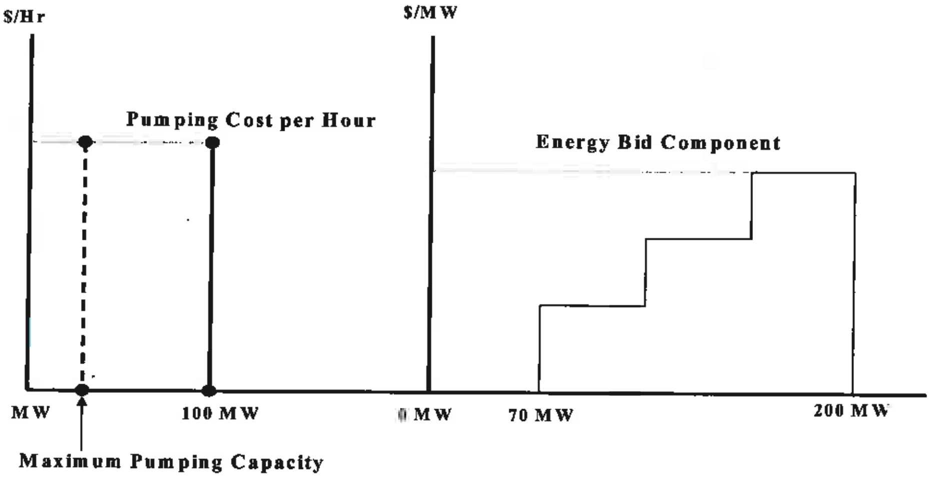


Pumped-storage hydro generators and price-responsive loads (e.g., pumping load) can choose to operate in either generating or dispatchable demand modes, based on their operational needs and market conditions, and can submit bid components for both modes. A participating load is treated in the same manner as the pumping component of the pumped-storage hydro units. In addition to the bid components regularly associated with operating in generating mode, pumped-storage hydro units submit the following three bid components representing their pumping mode:

- Pump shut-down cost, expressed as a dollar amount for a discrete MW block,
- Pumping level, expressed in MW (positive value), and
- Pumping Cost – The hourly cost of pumping, expressed in $/hour for the MW pumping level.

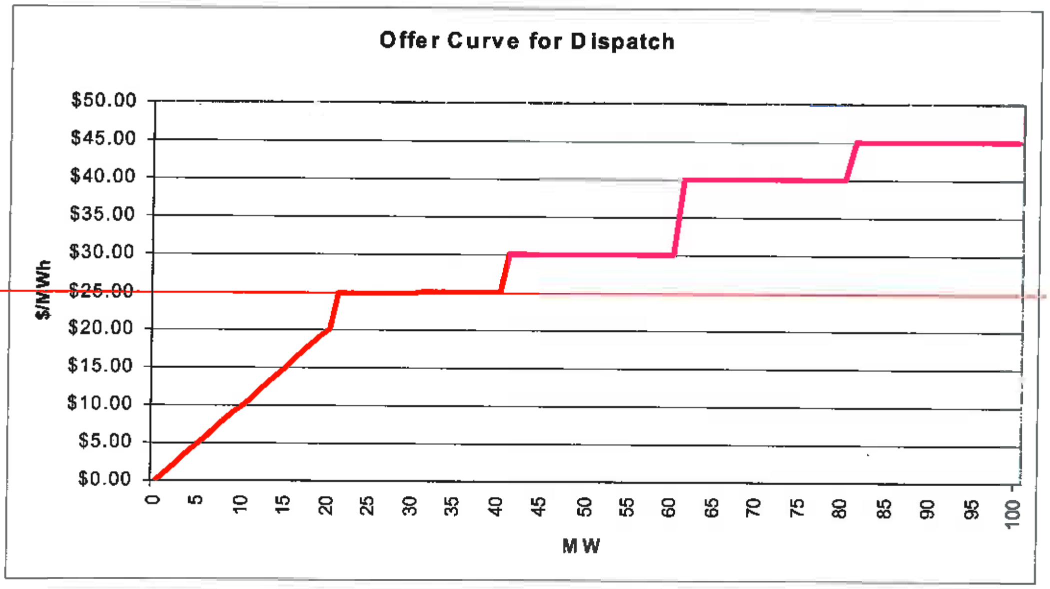
These combined bid components for the generation and dispatchable demand modes are illustrated in Example 2.

Example 2: Offer Curve for Pumped Storage Hydro Dispatch



Submitted Data

MW	$
0	$0.00
20	$20.00
21	$25.00
40	$25.01
41	$30.00
60	$30.01
61	$40.00
80	$40.01
81	$45.00
100	$45.01



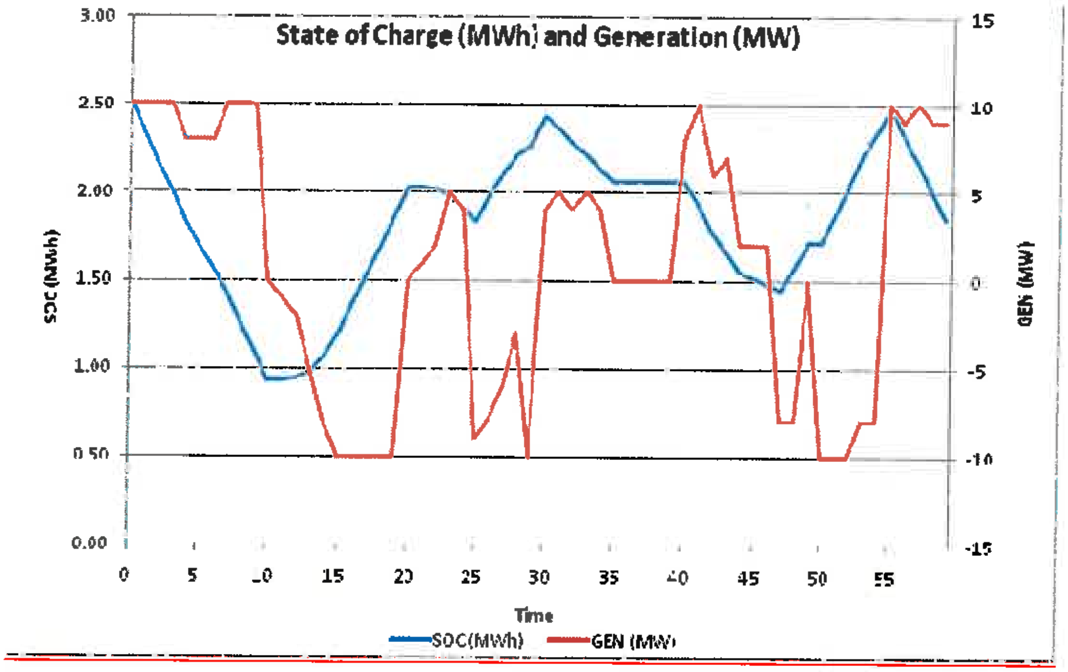
Non-Generator Resources (NGRs) operate as either generation or load to provide energy and ancillary services, and can be dispatched continuously to any operating level within their entire capacity range and within a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy. NGRs include but are not limited to limited energy storage resources (LESR). By modeling the generation range from negative to positive, the NGR model provides NGRs the same opportunity as generators to participate in the CAISO energy and ancillary service markets subject to meeting eligibility requirements. Because of the continuous operating range, NGRs do not have minimum load operating points, state configurations, forbidden operating regions, or offline status (unless on outage). Therefore they do not have startup, shutdown, minimum load, or transition costs.

The energy limits (MWh) for NGR are the maximum or minimum energy the device can store; this energy can be stored in the form of electrical charge, chemical energy, potential energy, or kinetic energy and it can be discharged to generate electricity. Based on an initial stored energy (state of charge), the continuous energy consumption or generation is constrained by the maximum or minimum stored energy limit (specified in the Master File), accounting for inherent losses while charging and discharging. For NGRs that elect not to use Regulation Energy Management (REM), the day ahead and real-time markets observe the energy limits in the energy and ancillary service optimizations. For NGRs using REM, energy limits are observed in real-time economic dispatch only. The energy limits are not required for the resource if the resource does not have that physical limitation.

The algebraic power output of a NGR is limited between a minimum and a maximum capacity, which can be negative. The maximum capacity (positive) represents the MW injected to the grid when it is discharging at its maximum sustainable rate; minimum capacity (negative) represents the MW withdrawn from the grid when it is charging at its maximum sustainable rate. NGRs have distinct ramp rates for operating in a consuming mode (charging) or in a generating mode (discharging), but is limited to one segment for each mode.

REM functionality allows an NGR to purchase or sell energy in real-time to meet the continuous energy requirements for regulation procured in the day-ahead market and real time market. When a resource elects REM, the regulation capacity awarded in the day-ahead market is evaluated as four times the regulation energy it can provide within 15 minutes. The buying and selling of energy in the real-time market supports the regulation obligation. NGRs using REM do not participate in the ISO's energy market or operating reserves.

The graph below represents the relationship between energy and generation of the NGR storage device (LESR). State of Charge (SOC, in MWh) reflects the remaining stored energy level of NGR. Generation (Gen, in MW) reflects the instantaneous MW the NGR can inject (discharge as positive value) or withdraw (charge as negative value) from the system. For the period of time that Gen >0 (discharge), the SOC will decrease. For the period of time that Gen<0 (charge), the SOC will increase. In the example, the NGR has an upper charge limit (UCL) of 2.5 MWh and a lower charge limit (LCL) of 0 MWh, Pmax = 10 MW, and Pmin = -10MW. The limits will be enforced in the market and operation. The SOC will be constrained by lower and upper charge limits. The generation will be constrained by the minimum and maximum capacity.



Additional details are provided in the Business Practice Manual for Market Operations.

The deployment of all resources is calculated using a security constrained economic dispatch to arrive at a least cost solution. When transmission constraints cause a re-dispatch by MO, the LIP's may differ.

6 Energy Schedules

6.1 Introduction

Energy schedules are submitted reflecting bilateral and Self-dispatched activities. Source and sink information on the energy schedules must match the ~~NERC Registry~~ Market Operator's master file. Schedules that source or sink within the Market will be rejected if they are submitted without an appropriate market source and/or sink mapped to a Settlement Location. EIM requires all scheduled injections to equal scheduled withdrawals plus losses. Although scheduling of all Load is not required, principles observed are (1) Market Participants will not be paid (due to under-scheduling) for providing counterflow when serving firm Energy Obligation (Resources providing energy that serves their firm Energy Obligation), and (2) Market Participants will not be allowed to profit from submitting schedules in excess of their firm Energy Obligations.

6.2 Content

Energy Schedules consist of hourly values for each Settlement Location must be submitted by ~~30~~ approximately 40 minutes prior to the start of the schedule for tagged transactions or 20 minutes prior the start of the schedule for the NLPS transactions and must have been approved at least 20 minutes prior to start of schedule. ~~Due to the NERC approval guidelines, approval may take 10 minutes on tagged transactions.~~ These schedules do not have to include all Load for which the MP is responsible; however, the energy withdrawn and the energy received must match for each hour.

Energy Schedules will be classified as one of two types under the Market depending on the Resource Status submitted in the Resource Plan. If the source for the Energy Schedule is a Self-Dispatched Resource, the schedule will be a Physical Schedule. If the source for the Energy Schedule is offered into the Market for MO Dispatch or the source is a Settlement Location for Load, the schedule will be considered a Market Schedule.

MP's may submit schedules and Offers for each of their Resources. If the MP submits both a schedule and an offer, the dispatch system will ignore the scheduled output for each Resource and calculate a Dispatch Instruction for the Resource based on the Offer Price and the information in the Resource Plan. In this case the Energy Schedule will be considered a Market Schedule since the scheduled amount is only relevant to Market Settlement and the physical operation of the unit will be driven by the economics of its offer. If the MP submits an Energy Schedule sourcing from a Self-Dispatched Resource, that schedule will be considered a Physical Schedule. This is due to the fact that a Self-dispatched Resource will be expected to physically operate to its scheduled amount. In this case the schedule still goes to the Settlement process but the Resource will also receive a Dispatch Instruction based on the total scheduled amount for the Self-Dispatch Resource.

Energy Schedules are submitted through ?? Scheduling SystemXX and Native Load and Portfolio Scheduling Tool (NLPS), utilizing the procedures found in scheduling documentation.

For Energy Schedules within, out of, or into the Market to be approved, ~~NERC registry entries~~ resource locations for Market sources and sinks must be mapped to valid Settlement Locations in the Market Operator's master file, and sources and sinks between BAAs must be mapped to NERC registry entries. Market Operator maps the Purchasing Selling Entity (PSE) and Transaction System Information Network (TSIN) Sink/Source entry to Settlement Locations based on request. Contact your MO Customer Relations representative for assistance in the mapping.

6.3 Timing and Submission

Modified Energy Schedules, must be submitted and approved under the same timing as Section 6.2. Market Participants shall submit actual values for Dynamic Schedules to Market Operator prior to 0600 PPT on the business day prior to the 5th calendar day following the Operating Day in time for the Initial Settlement. Reserve Sharing schedules identifying Resources may be input until 0100 three days after the Operating Day.

6.4 Use of Data

Energy Schedules are used in the calculation of generation needs (imports/exports from the Market footprint), used in the MO dispatch of Resources and the resulting market area NSI calculations and the calculation of EIM charges. See Section 7 on Deployment.

6.5 Schedule Corrections

The modification of schedules (all types) will be allowed when the scheduled interchange is invalid in the ?? Scheduling System and/or the Market Settlement System. The modifications will be made so that the schedule values will match in the MO's schedule system and market system to the new values. Any schedule changes, initiated by a MP, after the issuance of the Initial Settlement statement must be initiated through the dispute procedures outlined in the Market Protocols.

Upon notification through a dispute or Market Operator finding the issue, the schedule will be investigated to determine the required action to correct the schedule. After receiving approval from the Balancing Authorities that are either the Point of Receipt or Point of Delivery on the schedule and the Market Participants that are either the source or the sink on the schedule, Market Operator will correct the values in the settlement system.

6.5.1 NLPS and Tagged Energy Schedules

Energy Schedule modifications are permitted when a system failure such as a failure to properly transfer data from ETAG to ?? Scheduling System, causes the schedules to be incorrectly reflected in all the applicable computer systems.

6.5.2 Tagged Dynamic Schedules

Dynamic Schedule modifications are permitted when a system failure or other error (includes non-MO computer systems), such as an incorrect calculation or a revision to the associated metered data, causes the previously reported actual schedule value to be incorrect.

6.6 Scheduling Requirements

6.6.1 Load Scheduling Requirements

Market Participants are not required to submit schedules to cover their anticipated firm Energy Obligations at each Settlement Location for each Settlement Interval, but Market Participants that do not schedule Load accurately may be subject to disgorgement of profits pursuant to Section 11.4.2.

In order to determine the amount of revenue a MP must disgorge from a failure to submit counterflow schedules, the following general process will be applied for each Settlement Location:

- After real-time operations, a MP's Resources and Load are placed in order from lowest to highest LIP and differences between the schedules and actuals are computed.
- Starting with the lowest LIP Resource, the scheduled output or actual output (whichever is greatest) is counted towards meeting the MP's Load Scheduling Requirement, starting with the lowest LIP Load
- Schedules on congested paths (i.e., where the Resource LIP is < the Load LIP) would not be added or adjusted
- Continue moving up the MP's Resource stack until all of the MP's Loads are accounted for or the MP runs out of Resources
- If an MP's Resource LIP exceeds the MP's Load LIP before all of the MP's Load is accounted for, the excess output up to the MP's firm Load requirement is considered unscheduled counterflow. An MP's actual generation above what is needed to serve its firm Load requirements is not considered unscheduled counterflow.
- The MP will be charged the difference in LIPs between the schedule's source and sink multiplied by the unscheduled counterflow MWs.
- This process will be applied during all applicable settlement periods (Initial, Final, and any Resettlement)
- For this process, MO submitted ARS Schedules are considered as the MP's firm Load requirement.

In order to determine the amount of revenue a MP must disgorge from submitting schedules that exceed a MP's firm Load requirement, the following general process will be applied:

- After real-time operations, a MP's Resources are placed in order from highest to lowest LIP and differences between the schedules and actuals are computed.
- For overscheduled Load, the overscheduled MWh from highest priced Resources, moving through the stack, are reduced until the overscheduled amount of Load is offset.
- The schedules from Resources are not reduced below the actual output of the Resource.
- Schedules from counterflow Resources will not be reduced.
- The MP will be charged the difference in LIPs between the schedule's source and sink, where the sink price is higher, multiplied by the overscheduled MWs.
- This process will be applied during all applicable settlement periods (Initial, Final, and any Resettlement)
- For this process, MO submitted ARS Schedules are considered as the MP's firm Load requirement

6.6.2 Resource Scheduling Requirements

The sum of Market Participant schedules sourcing from a Self-Dispatch Resource shall not exceed the "MaxMW" of the Resource submitted in the Resource Plan for any Settlement Interval.

Each Market Participant is required to provide sufficient energy available to the Market to serve the MP's obligations at all times. MPs must satisfy their energy obligations by scheduling energy from third parties, causing its Self-Dispatched Resource to operate at Scheduled Megawatt levels and/or making its Resources available to the Market for dispatch with sufficient dispatchable operating range such that in aggregate they are capable of producing sufficient energy to be capable of serving the MPs obligations at all times. MPs must satisfy their ancillary services obligations, including operating reserve requirements, by submitting an Ancillary Services Plan which demonstrates their ancillary service requirements are being met.

<u>Examples of Satisfying Energy Requirements</u>

A Market Participant with an obligation of 500 MW at Settlement Location(s) in a particular hour and two Resources, each having a MinEconMWlimit of 60 MW and MaxEconMW limit of 300 MW, could do any of the following:

(1) **100% Self Dispatch** - Self Dispatch both of its Resources, indicate it intends to operate its Resources on its Resource Plan at an aggregate of 500 MW and generate in real time 500 MW, consistent with the schedules. The MP must also schedule an aggregate of 500 MW from its Resource Settlement Locations to meet its Energy Obligations.

(2) **100 % Offered for dispatch** - Make both of its Resources available for MO dispatch such that MO can calculate economic base points within the their operating range of 60 MW to 300 MW on each unit. While not explicitly required, the MP could also choose to schedule from its Resource Settlement Locations.

(3) **Hybrid** - Make one of its Resources available for MO dispatch such that MO can calculate economic base points within its operating range of 60 MW to 300 MW. Self Dispatch its other Resource by indicating on its Resource Plan that it intends to operate that Resource at some level at or above 200 MW and generate in real time consistent with that indication. The MP must also schedule 200 MW from the Self-Dispatched Resource Settlement Location. Self-Dispatch of the second unit at or above 200 MW is required so that the remaining requirements can be covered by the Resource that is made available for MO dispatch. While not explicitly required, the MP could also choose to schedule from its offered Resource Settlement Locations.

6.6.3 Network/Native Load and Portfolio Scheduling

A Native Load and Portfolio Schedule (NLPS) is a unilateral schedule between one or more Resource Settlement Locations and Load Settlement Locations registered by the same Transmission Customer in the same Balancing Authority Area. NLPS schedules do not utilize NERC tags.

Transmission Customers will have the ability to enter their NLPS into MO's Native Load and Portfolio Scheduling Tool (NLPS). Transmission Customers are not required to use NLPS. Such schedules will be included with all other schedules sent to the settlement system, and will have the same impact on settlement as any other type of schedule. Due to their special nature as unilateral schedules, NLPS schedules are subject to special rules.

Special rules applied to NLPS are as follows:

- NLPS will be allowed only between Settlement Locations registered by the same Transmission Customer.
- NLPS will be allowed only between Settlement Locations in the same Balancing Authority Area.
- NLPS will be validated against the transmission capacity associated with the Designated Resources.
- NLPS may be adjusted for a given Operating Hour no later than 20 minutes prior to the beginning of the schedule start or change (beginning of ramp).
- NLPS is not permitted from Resources in the Unavailable status.
- NLPS is permitted from Resources in the Available Quick-start status.
- Schedules conforming to these rules shall be automatically accepted.

6.6.4.1 *Portfolio Schedules*

Market Participants may make portfolio sales from their commonly dispatched Resources. Schedules for these sales will be treated as Portfolio Schedules (PS). PSs will be scheduled by the Market Participant from its Load Settlement Location. PSs must be supported by Transmission Service purchased for this purpose. The portion of the NLPS attributable to the Market Participants Network Transmission Service will be determined by subtracting (a.) the sum of the Portfolio Schedules; from (b.) the NLPS to that load Settlement Location.

6.6.4.2 *Native Load and Portfolio Scheduling Tool*

The Native Load and Portfolio Scheduling Tool (NLPS Tool) will be used to submit a single NLPS from each Resource to the Market Participant's load Settlement Location. Within the tool, the NLPS will be maintained as two components to account for the usage of each NLPS that is serving Native Load (i.e. NLS) and that which is supporting Portfolio Schedules (i.e. NLPR).

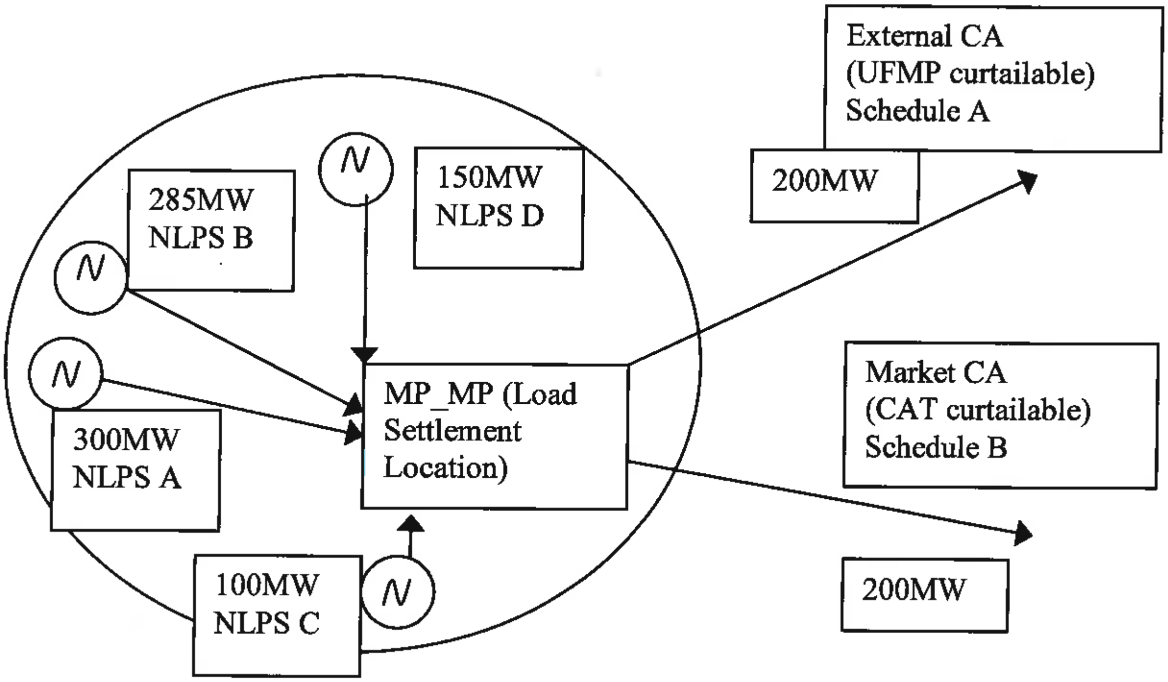
6.6.4.3 *Process for determining NLS and NLPR*

The Market Participant will have the option to specify an amount of NLPR for each Resource and have any additional NLPR needed to support all PSs allocated in an automated fashion. The following outlines the steps for determining the NLS and NLPR amounts of each NLPS schedule.

1. The NLPS Tool shall sum all of the PSs sourcing from the MP's load Settlement Location.
2. The NLPS Tool will subtract any manual NLPR amount specifically identified as supporting PSs.
3. The remainder will be allocated among the resources within the MP's Resources identified in the NLPS Tool.
    a. For each NLPS, the Market Participant will submit a participation factor for use in the automatic prorating process. This field should be a percentage from 0-100% representing the maximum percentage of the NLPS the MP wants to allow for support of PS.
    b. For each NLPS, the Market Participant will submit a prioritization identifier. This will be an integer value with 1 being the highest priority for the automated allocation process. The same prioritization identifier may be used for multiple NLPS.
    c. The Tool shall create 'NLPR' schedules sourcing from the resources on a priority basis using the priority identifier described in step 3b. If multiple NLPS have the same prioritization identifier, all NLPS in that priority group will be prorated based on NLPS weighted by the participation factor of the NLPS.
4. In the case that the sum of the NLPS amounts times the respective participation factors are insufficient to meet the total PS, the deficit amount will be allocated using the following pecking order:
    a. Resources without Manual NLPR schedules prorated by any remaining NLPS not used in the initial process. This would include any Resources with a 0% participation factor.
    b. Resources with Manual NLPR schedules prorated by any remaining NLPS not specified in the Manual NLPR
5. In the case that the sum of all NLPS submitted does not meet the total PS, all NLPS submitted will be allocated as NLPR and NLS for NITS will be 0 on all Resources.
6. NLPR Schedules shall be subtracted from the submitted NLPS Schedules on each resource. The result will be NLS (Native Load Schedules utilizing Network Integrated Transmission Service (NITS))

This schedule creation logic shall run every 5 minutes for the current and next operating hour.

NLPR and NLS Determination Example:



An MP has a 300 MW NLPS with 100% participation factor priority 1, one 285 MW NLPS with a 70% participation factor priority 2, one 100 NLPS with 100% participation factor priority 2 and a 150 MW NLPS with a 0% participation factor. The sum of the Portfolio Schedules is 400MW, and the scheduler creates a 50MW manual 'NLPR' from the resource with a 0% participation factor. The 400 MW total Portfolio Schedule value is reduced by the 50 MW manually created NLPR resulting in a 350MW requirement to be automatically allocated. The 300 MW NLPS has the highest priority and with a 100% participation factor. The first 300 MW will be allocated to this NLPS. The remaining 50 MW will be allocated to NLPS B and C that both have priority 2. Using the weighted participation, the allocation would be (285*.7)*50/(285*.7 + 100*1) = 17 MW for NLPS B and (100*1)*50/(285*.7 + 100*1) = 33 MW for NLPS C.

Resource	Capacity	Submitted NLPS	NLPR (Manual)	Total Portfolio Schedules	Participation Factor %	Prioritization Identifier	NLPR (Automatic)	NLS (NITS)
A	300	300			100	1	300	0
B	400	285			70	2	17	268
C	100	100			100	2	33	67
D	200	150	50		0		0	100
Total	900	735	50	400		1	350	435

6.6.4 Reserve Sharing Scheduling

NERC policy will continue to dictate reserve sharing deployment. Whereas each Reserve Sharing computer system facilitates the reserve sharing program, the energy schedules implemented through the reserve sharing deployment are settled as bilateral transactions and will continue to remain so in the context of the EIM market. As with all bilateral transactions in the EIM Market, however, any deviation between the schedules and actual meter values at each settlement location will be subject to EIM at the appropriate LIP.

An Operating Reserve Contingency should be immediately reported to the applicable Reserve Sharing System (RSS). This includes Resources owned by Market Participants that are not Reserve Sharing Group (RSG) Members.

The RSG includes members that may not directly participate in the EIM market, i.e., are not members of the market. Nothing in the EIM Market Protocols should prohibit these entities from continuing to participate in the RSG; nothing in the EIM Market Protocols should subject these entities to changes in their internal business practices.

The RSS automatically creates replacement energy schedules for contingencies. The automatically generated schedules created by reserve sharing events are treated and settled as bilateral transactions in the context of the EIM market. These bilateral transactions are considered Market Schedules. For each contingency, up to three types of schedules will be automatically created: 1) a schedule (contingency schedule) from a designated Load Settlement Location of the contingent Balancing Authority Area to the Settlement Location of the reported Generation Resource that suffered the contingency (contingent resource), 2) schedules sourced from designated Load Settlement Locations of the assisting[1] Balancing Authorities to the designated Load Settlement Location of the contingent Balancing Authority, when assistance is needed, and 3) schedules, internal to the assisting Balancing Authority Areas, from the specific Resources expected to be deployed in response to an RSS event, to the designated Load Settlement Location of each assisting Balancing Authority Area required to respond to the event. The reserve sharing systems shall provide the contingency schedules, as described in item (1) above, using a?? Scheduling System push, to the Market Participants representing the contingent resource and the Load Settlement Location of the contingent Balancing Authority.

Market Participants providing assistance for a reserve sharing event deploy specific Resources at their discretion to respond to the event. This process will continue in the context of the EIM market. Schedules of energy deployment from Operating Reserves will ensure that Self-dispatched Resources are sent consistent instructions and allow the MOS to utilize capacity from Market Resources allocated as Spinning and/or Supplemental Operating Reserves in the applicable Ancillary Service plans. Market Participants may provide such schedules using one of the following methods.

1. Enter Resource specific RSS schedules immediately.
2. Supply a default distribution prior to real-time that will automatically generate RSS schedules.

3. Supply a default distribution and override the default with Resource specific RSS schedules.

Absent these schedules from one of the above methods, the Market System will send dispatch instructions based upon pre-event operating limits. To the extent actual response differs from the schedules automatically created, Market Participants are expected to supply in RSS schedules from the actual Resources deployed during the event by no later than 0100 three days after the Operating Day in which the event occurred for settlement purposes.

In instances where the MO's market systems have collected data for the next deployment calculation wherein a resource contingency has occurred but corresponding RSS schedules have not been received by MOS, Market Operator shall utilize the previous interval deployment for the contingent resource in calculating deployments for the intervals between the contingency occurrence and receipt of RSS Schedules in order to prevent both RSS and MOS deployment for the loss of the resource. Market Operator staff will apply criteria to determine which contingencies trigger this event. These criteria may include; MW magnitude, Breaker status, and/or MW rate-of-change thresholds and Market Operator Staff may revise the criteria from time to time following discussion with EIM stakeholders, and ~~with~~ approval from the EIM governance structure if needed ~~Market Working Group and Operating Reliability Working Group~~.

Note that after the recognition of the reserve sharing schedules within the market system, the deployment of resources takes place based on the processes of market dispatch. But individual BAAs remain responsible for their share of DCS compliance under the terms of their reserve sharing group agreement.

6.6.5.1 *Operating Reserve Contingency inside the market footprint*

Contingency Area (Balancing Authority Area/reserve sharing member experiencing an Operating Reserve Contingency)

1. Submit request for support to reserve sharing system.
2. Continue to Follow Dispatch Instructions for Resources not designated as carrying Contingency Reserves in A/S Plan.
3. Ramp own other Resource(s) designated as carrying Contingency Reserves in A/S Plan to meet Reserves obligation.
4. Reserve sharing system will create Reserve Sharing Schedule from the Contingency Area's Load Settlement Location to lost Resource's Settlement Location for the entire amount of the loss.
5. Continue to operate according to the NSI as adjusted by MO for RSS Schedules.
6. By 0100 three days after the Operating Day in which the event occurred, and consistent with the scheduling requirements of Section 6.5, the responding market participant will enter or update Resource specific schedules from those Resources ramped to meet the Assistance Schedules.

7. Return to following Dispatch Instructions for all units for the Deployment Interval ending 16-20 minutes after the contingency. If uneconomic Contingency Reserve Resources are physically unable to get to new set point, ramp towards set point to the best of the unit's ability. Uninstructed Resource Deviation penalties will not apply to the units carrying Contingency Reserves for the full duration of the reserve sharing event.

Internal Responding Area (EIM Market/Participating Balancing Authority/reserve sharing member providing Reserve support)

1. Reserve sharing system will create Reserve Sharing Schedule from Responding Area's Load Settlement Location to Contingency Area's Load Settlement Location. ?? Scheduling System NSI will be automatically updated.
2. Continue to Follow Dispatch Instructions for Resources not designated as carrying Contingency Reserves in A/S Plan.
3. Ramp Resources identified in the latest A/S Plan as carrying Contingency Reserves to respond to request for Reserves support.
4. Continue to operate according to the NSI as adjusted by MO for the RSS Schedules.
5. By 0100 three days after the Operating Day in which the event occurred, and consistent with the scheduling requirements of Section 6.5, the responding market participant will enter or update Resource specific schedules from those Resources ramped to meet the Assistance Schedules.
6. Return to following Dispatch Instructions for all units for the Deployment Interval ending 16-20 minutes after the contingency. If uneconomic Contingency Reserve Resources are physically unable to get to new set point, ramp towards set point to the best of the unit's ability. Uninstructed Resource Deviation penalties will not apply to the units carrying Contingency Reserves for the full duration of the reserve sharing event.

External Responding Area (Reserve sharing Member Balancing Authority Area not participating in EIM)

1. Respond to Reserves Request.

6.6.5.3 Operating Reserve Contingency outside the market footprint but in an reserve sharing Member Balancing Authority Area

Internal Responding Area

1. Reserve sharing system will create schedules from Load Settlement Location to External RSG Member's NERC registered POD/Sink. Schedule system NSI will be updated accordingly.
2. Continue to Follow Dispatch Instructions for Resources not designated as carrying Contingency Reserves in A/S Plan.
3. Ramp Resources identified in the latest A/S Plan as carrying Contingency Reserves to meet request for Reserve support.

4. Continue to operate to NSI received from MO
5. By 0100 three days after the Operating Day in which the event occurred, and consistent with the scheduling requirements of Section 6.5, the responding market participant will enter or update Resource specific schedules from those Resources ramped to meet the Assistance Schedules.
6. Return to following Dispatch Instructions for all units for the Deployment Interval ending 16-20 minutes after the contingency. If uneconomic Contingency Reserve Resources are physically unable to get to new set point, ramp towards set point to the best of the unit's ability. Uninstructed Resource Deviation penalties will not apply to the units carrying Contingency Reserves for the full duration of the reserve sharing event.

External Responding Area

7. Respond to Reserves Request accordingReserve Sharing Group.

6.6.5 Loss Compensation

The Tariff requires Transmission Customers to replace transmission loss energy owed to the Transmission Owner(s) on a real time basis. Losses associated with all transactions shall be determined in accordance with the provision of Attachment ??? of the Tariff.

6.6.5.1.1 DBA for Transactions with Self-Provided Losses

MO will require all MPs associated with BAs to notify MO of their registered Settlement Location(s) to be used for receiving self-provided losses.

MO will permit all potential DBAs to register a unique loss Settlement Location to be used exclusively for the purpose of receiving losses as the DBA. The LIP associated with that unique loss Settlement Location shall be the LIP for the DBA's load Settlement Location. Such loss Settlement Locations shall not have any associated metered Resources or Loads and shall not be subject to any of the scheduling provisions found in section 6.5.

The credit reflected in the settlement for Energy Imbalance Service for the loss Settlement Location identified by the DBA will be offset exactly by the amount of the DBA Loss Charge on each settlement statement.

?? BA will act as the DBA upon implementation of the market. After one year and with at least 120 days notice, the DBA shall have the option to terminate this designation effective on the first day of a calendar month. Upon such notification, MO will perform an analysis to determine the new DBA and notify such DBA within 20 days.

For a Transmission Owner having multiple load Settlement Locations, the MO analysis will select the load Settlement Location to be associated with the loss Settlement Location. MO will calculate the regional loss weighted average cost for the prior 12 months by dividing the total Loss payments to the MPs associated with Transmission Owners by the total MWH of self provided losses in the same period. From the BAs representing minimum loads in the upcoming year of at least 500 MW, MO shall select the DBA associated with the Settlement Location having the average LIP for the prior 12 months closest to this regional loss weighted average cost.

6.7 MO Operational Information Exchange

Updates to Operating Day Data		
Timeline	**Market Participant Action**	**MO Action**
Immediately following an RSS event	May enter Resource specific RSS schedules for responding Resources as outlined in Section 6.5.4 Reserve Sharing Scheduling. Deploy energy in response to the RSS event.	One Schedule for the amount lost is created in RSS from the Contingent Balancing Authority Area Load Settlement Location to the Settlement Location for the Contingent Generator Resource. Schedules from the Load Settlement Locations of the assisting Balancing Authority Areas to the Load Settlement Location of the Contingent Balancing Authority Area are created in RSS. Resource specific schedules are created in RSS from the Resources expected to be deployed in response to an event to the Load Settlement Location of the Balancing Authority Area responding to the event. See Reserve Sharing Group's Criteria.

0100 three days after the OD in which the RSS event occurs	Schedules representing actual reserves deployed during an event are submitted in ?? Scheduling System from each Resource to the Load Settlement Location of the Balancing Authority Area responding to the event.	

6.8 Schedule Curtailment/Adjustment under MO Congestion Management

Except as provided for Emergency conditions in Section 1, when an actual or potential constraint is observed in real-time, a MO Congestion Management Event (CME) will be automatically initiated within the MOS, and the constraint will be activated in the MOS. The CME can be initiated through declaration of a UFMP or an activation of a constraint in MOS. BA will declare a UFMP if applicable, in which case MO will adjust the applicable constraint's limit to the value determined by the BA. If there are no such UFMP declared by a BA, MO ~~may~~ will initiate the CME directly in MOS by automatically activating constraints for which flows exceed 85% of their capacity, and not issue a UFMP.

The CME will cause MOS to deploy Dispatchable Resources to provide appropriate reduction in flows as needed to ~~relieve~~ manage the constraint. The BA will determine if UFMP should be intiated. In conjunction with the constraint activation, MO Curtailment/Adjustment Tool (MO CAT) within MOS will manage curtailments of Energy Schedules as appropriate. MO will use the combination of CAT and MOS to reliably manage and economically maximize the flow of power on flowgates to within the applicable operating limits as prescribed by NERC.

During an MO Congestion Management event, EIM impacts greater than zero ~~in a particular priority~~ will be removed before curtailing any existing schedules, because dispatches issued by EIM are considered to have ~~in the same~~ priority level zero (0), lower than any existing self-schedules. Since the ~~current MO Market Structure provides no mechanism to~~ EIM settlements directly assign the cost associated with relieving congestion to the schedules that have uninstructed deviations that are impacting a particular constrained flowgate, as well as setting LIPs for EIM dispatches based on their contribution to causing or relieving congestion, the CAT ~~shall~~ is a cost-based mechanism for curtailing/adjusting schedules to ~~achieve a relieving impact equal to the amount of~~ provide Energy Imbalance to support~~ing~~ scheduled flows. The result of such curtailment procedure will be that flows resulting from the EIM market dispatch will ~~not~~ provide counter-flows, and thereby ~~to~~ support scheduled flows that ~~are~~ may otherwise need to be curtailed as described earlier. EIM will provide congestion management to the extent possible using its available bids, and when available bids are inadequate to manage constraints, will notify BAs to consider declaring a UFMP.

6.8.1 MO Congestion Management under UFMP Operations

If the BA determines to initiate the UFMP, MOS, the WECC UFMP and the MO Curtailment/Adjustment Tool (MO CAT) will work with each other to manage congestion on constrained flowgates and handle curtailments of Energy Schedules as appropriate.

The appropriate UFMP must be requested by the BA. The UFMP will prescribe curtailments of those tags that are not included in Market Flows. The MO will also prescribe curtailment of Market Flows in the event that EIM bids become available that would be effective in managing the applicable constraint and that MOS has not already utilized. MO will ~~then activate or~~ continue activation of the constraint in MOS until flows are less than 85% of its capacity. This will ensure that EIM continues to provide the maximum amount of congestion relief possible given its available bids, thereby reducing needs for a BA to initiate UFMP. ~~In the meantime, CAT will receive the Market Flow relief obligation from the MO. Used in conjunction with Market Flows received from MOS, CAT will calculate EIM and appropriately curtail/adjust those schedules included in Market Flow.~~ All curtailments are fed into ?? Scheduling System from the UFMP and CAT to facilitate proper generation response for Self-dispatched Resources. LIPs will ~~not~~ be updated after a schedule curtailment ~~until~~ once those curtailments are recognized in the Market dispatch.

6.8.2 UFMP/CAT Schedule/tag Management Identification

The following table is provided to describe those types of schedules that the UFMP is responsible to explicitly curtail and those that CAT is responsible for curtailing and/or adjusting. For purposes of this section of the Protocols, the term "curtailment" is used to describe an action taken with respect to a schedule that is expected to elicit a specific generation response in near real-time, while the term "adjustment" is used to describe an action taken to a schedule to reflect generation dispatched by the Market in real-time for after-the-fact settlement purposes.

An assumption in this table is that the External BA does not have a dynamic transfer (dynamic schedule or pseudo-tie) to a Market BA. A dynamic transfer can effectively make its designated resource available to the EIM to add to EIM's ability to manage congestion as well as to balance load and supply variations, and thereby reduce the need to utilize UFMP. The use of dynamic transfers in this way is encouraged for these reasons and for market-to-market or market-to-non-market coordination.

Schedule	*Source*	*Source BA*	*Sink*	*Sink BA*	*Curtailed/ Adjusted by*
1	Dispatchable Resource	Market BA	External	External BA	UFMP
2	Dispatchable Resource	Market BA	Load Settlement Location	Market BA	CAT

3	Self-Dispatched Resource	Market BA	External	External BA	UFMP
4	Self-Dispatched Resource	Market BA	Load Settlement Location	Market BA	UFMP
5	Self-Dispatched Resource	Market BA	Load Settlement Location	Market BA (where GCA = LCA)	CAT
6	Load Settlement Location	Market BA	External	External BA	UFMP
7	Load Settlement Location	Market BA	Load Settlement Location	Market BA	CAT
8	External	External BA	External	External BA	UFMP
9	External	External BA	Load Settlement Location	Market BA	UFMP

6.8.3 Market Flow

EIM's congestion management, and BAs' use of UFMP when EIM has exhausted its available, effective market bids, will be supplemented by market-to-market and market-to-non-market coordination agreements between EIM and non-participating areas. A presentation at the WECC Seams Issues Subcommittee's November 2010 meeting (available at http://www.wecc.biz/committees/StandingCommittees/MIC/SIS/SIS111510/Lists/Exhibits/1/WECC_SIS_EIM_MarketCoordination_20101109_final.doc and http://www.wecc.biz/committees/StandingCommittees/MIC/SIS/SIS111510/Lists/Presentations/1/WECC%20SIS%20Market2Market%20StrawProposal%2020101115_final.ppt) explained that the specific details used in some market areas (e.g., Southwest Power Pool's Congestion Management Process (CMP) would not meet the needs for coordination with a comprehensive central market such as the California ISO operates. The reasons for this conclusion include:

- Firm market flows in CMP include long-term contracts, and CMP distinguishes non-firm flows, whereas all transmission sold by CAISO is equivalent to hourly firm.
- Loads in CAISO depend more on imports from other parts of WECC. Imports to CAISO use transmission for which entities sell their transmission rights through external BAAs to CAISO market participants.

The presentation proposed a framework that addresses (1) routine market dispatch and (2) mutual assistance for congestion management. Routine market dispatch would build on the EIM's functionality for external-to-internal market integration (which is already implemented in the CAISO's market software), plus dynamic transfer functionality. EIM will include external sources and sinks in its market network model to accurately model flows between EIM and areas with which it coordinates. External resources may then participate in EIM as dynamic transfers, including aggregations and partial resources.

Mutual assistance for congestion management then builds on accepted principles within WECC, for instances when EIM or another area has insufficient resources itself (including dynamic transfers with other areas) to effectively manage congestion. WECC has established procedures for path ratings, and market operators and other system operators would use a similar process to agree on limits for coordinated flowgates and criteria for resources that are responsible for contributing to enforcement responsibilities, such as flow contributions with PTDFs exceeding 10%, like UFMP. The proposed mutual assistance for congestion management simplifies CMP to the following steps:

1. Participating market or non-market system operators model full the WECC network, define external constraints in their models, and prepare to enforce constraints in step 4
2. Exchange load & generation forecasts and other data at granularity no larger than UFMP zones or equivalent, for accurate flow modeling
3. When a market or non-market system operator forecasts real-time congestion, other market or non-market system operators determine their own firm market flows on the coordinated flowgate
4. Each market or non-market system operator then enforces the coordinated flowgate to prevent further increases of its flow, allowing real-time redispatch to reduce flow
5. Each market or non-market system operator sends updated schedules and dispatch to UFMP.

~~As required by the Congestion Management Process (CMP) prescribed by the Joint Operating Agreement, MO will determine its Market Flows on all MO Coordinated Flowgates (CFs) and Reciprocal Coordinated Flowgates (RCFs). MO's CFs are those flowgates identified as being impacted by activities within MO. MO's RCFs are those flowgates identified as being impacted by activities within MO and one or more entities operating under the requirements similar to those of the CMP. Currently those entities include MO, XXX.~~

~~MO's Market Flows represent impacts from one or more of the following components:~~

~~1) The Native Load Schedule component of NLPS from both Market and Self-dispatched Resources. NLPR impacts are considered implicit in the Portfolio Schedules they are supporting and therefore are not included in Market Flow.~~

~~2) Tagged intra-Balancing Authority schedules from both Market and Self-dispatched Resources~~

~~3) Tagged schedules where the source is a market Resource or Load Settlement Location and the sink is a Load Settlement Location~~

~~4) Any unscheduled output from generation resources offered into the EIM Market and dispatched by MO in accordance with these Protocols (hereinafter referred to as "EIM impact.")~~

~~In accordance with the CMP, Firm Flow Limits are derived for CFs while both Firm and Non-firm Network limits are derived for RCFs. For CFs, MO will establish a Firm Flow Limit equal to the sum of firm transmission reservations and Gen-to-Load impacts. For RCFs, MO will establish a Firm Flow Limit based upon the allocation of Flowgate Capacity determined pursuant to the reciprocal coordination process. For CFs, MO will assign Firm (F-7) curtailment priorities to those Market Flows that are scheduled (i.e., categories 1-3 from the above list) using firm transmission service, up to the applicable Firm Flow Limit. On CFs, any remaining Market Flows will be assigned Non-firm Network (NN-6) curtailment priorities. For RCFs, MO will assign Firm (F-7) curtailment priorities up to the Firm Flow Limit established by the CMP. For RCFs, MO will assign Non-firm Network (NN-6) curtailment priorities up to the Non-firm Network Limit established by the CMP. On RCFs, any Market Flow in excess of the Non-firm Network Limit will be prioritized as Non-firm Hourly (NH-2).~~

~~At least every 15 minutes, MO will send Market Flow values for all CFs and RCFs to the BA in the appropriate priority levels for the current hour and next hour. During an MO Congestion Management event, the UFMP will use this information to prescribe appropriate reductions in Market Flows and curtailments of tags whose impacts are not reflected in Market Flows. MO systems will identify Market Flows that must be curtailed to achieve any obligation assigned by the UFMP by binding of the constraint in the security constrained economic dispatch system.~~

~~MO will determine the amount of Market Flows associated with EIM impacts by subtracting scheduled Market Flows from total Market Flows. For CFs, EIM impacts are considered to have Non-firm Network priority. For RCFs, any EIM impacts that cannot be allocated to the Non-firm Network priority will be considered to have Non-firm Hourly priority.~~

6.8.4 Maintaining Feasibility ~~under~~ Prior to UFMP Operations

Under the procedures described above, EIM will have fully utilized its available, effective market bids to manage congestion before a participating BA needs to invoke UFMP, by decrementing resources that contribute to congestion and incrementing resources that can provide counter-flow. For the purposes of maintaining feasibility during UFMP Operations, EIM flow ~~will be~~ has been adjusted first, based on the ~~appropriate curtailment priority of the effective UFMP~~ effectiveness of available market bids. If EIM flow ~~is~~ were increasing the congestion on a flowgate the EIM flow will have been removed through redispatch, through EIM's market optimization. If EIM flow is capable of providing relief on a flowgate, the ~~schedule impacts are~~ available resources have been adjusted ~~to remove the need for EIM relief,~~ to provide schedule feasibility. This process applies to flowgates in the MO Reliability Coordination footprint, for which UFMP is called.

~~The EIM flow on a given flowgate is determined by subtracting the sum of the net of CAT scheduled impacts with impacts >0% from the net market flow with impacts >0% calculated by the Market Flow Calculator (MFC).~~

~~The Physical Feasibility component is determined by subtracting the Real-Time Balancing Calculated Flow (calculated real-time flow from the Market Operations System) of the flowgate from the Effective Limit of the flowgate (limit placed on the constraint in the market dispatch system).~~

~~CAT shall sum both the EIM flow component and the Physical Feasibility component. If the result is negative, CAT shall curtail that amount of scheduled impacts. If the result is positive, CAT will reload the scheduled impacts and/or MOS will redispatch as appropriate.~~

~~CAT Curtailment Requirement = Market Flow (>0%) – Impact of CAT schedules (>0%) + Effective Limit of the constrained flowgate – Real-Time Balancing Calculated Flow of the constrained flowgate.~~

~~Example 1: CAT Curtailment Requirement = 300MW (Market Flow) – 400MW (Impact of CAT schedules) + 350 (Effective Limit) – 325MW (Real-Time Balancing Calculated Flow) = -75MW.~~

~~In example 1, because the sign is negative, indicating the CAT schedules are infeasible, CAT shall curtail 75MW of scheduled impacts. If infeasibility continues after all non-firm curtailments have been exhausted, a UFMP and/or a Congestion Management Event Level 5 shall be issued.~~

~~Example 2: CAT Curtailment Requirement = 500MW (Market Flow) – 400MW (Impact of CAT schedules) + 350 (Effective Limit) – 325MW (Real-Time Balancing Calculated Flow) = 125MW.~~

~~In example 2, because the sign is positive, indicating the CAT schedules are feasible, CAT will reload 125MW of CAT curtailed schedules and/or MOS will redispatch as appropriate.~~

6.8.5 UFMP Curtailments

The WECC UFMP will receive all tagged transactions involving MO. Under MO Market Operations, the BA will be responsible during UFMP events for prescribing curtailment of certain types of tagged transactions and coordinating with the Market Flow relief that MO must achieve internally through its Market Operations.

The WECC UFMP will be responsible for prescribing curtailment of only those tags involving MO for which impacts are not included in MO's Market Flows (see section 6.7.1). These include tags for schedules with external parties that are sourced or sunk in the MO Market and tags for Interchange Transactions from Self-Dispatched Resources.

Those tags for which impacts are included in MO's Market Flows will not be explicitly curtailed by the UFMP. As stated in section 6.7.1, included in MO's Market Flows are impacts of tagged schedules where the source is a Resource or Load Settlement Location and the sink is a Load Settlement Location. In order for the UFMP to distinguish those tags, MOS will communicate a market flag for each such Resource to the BA each hour based on information in the Resource Plan.

At least every 15 minutes, MO will also identify wherein the marginal unit(s) reside. This information will be used by the MO to calculate Transaction Distribution Factors (TDFs) for those schedules with external parties that source in the MO Market, and is available for use in UFMP. This is reflected in the MO as the ~~SWPP_EXP~~ EIM marginal zone. If a generation resource in the MO Market footprint is self-dispatched and has tagged schedules with external parties, the BA will use resource level granularity in determining the TDF impact on flowgates.

6.8.6 Market Flow Curtailments/Adjustments

Note: It has not been confirmed whether the following description is consistent with recent and pending changes to UFMP procedures and the future implementation of WECC's Enhanced Curtailment Calculator (ECC). The changes to UFMP and ECC procedures will apply to all entities in WECC, and this description would be revised accordingly.

If necessary under UFMP and ECC procedures, CAT will be used to compute curtailments/adjustments of those schedules for which impacts are included in Market Flows. These include the following types of schedules:

1) Native Load Schedules from both Market and Self-dispatched Resources

2) Tagged intra-Balancing Authority schedules from both Market and Self-dispatched Resources

3) Tagged schedules where the source is a market Resource or Load Settlement Location and the sink is a Load Settlement Location

Any curtailments or adjustments made by CAT will be based on the Market Flow relief responsibility determined by the BA, during a UFMP event, or the amount of EI supporting schedules, during a MO Congestion Management event where UFMP is not initiated. In all cases, it is the MO's responsibility to achieve the required Market Flow relief.

MO will first determine if the EIM component of the Market Flows at the priority is sufficient to achieve required Market Flow relief. If so, then EIM will be reduced to provide the required relief and no schedule curtailments or adjustments will be necessary. However, if the adjustment of the EIM component of Market Flow is not sufficient to achieve the required relief, the scheduled curtailments will be handled as outlined in the following sections. The MO CAT will use the same Transfer Distribution Factor (TDF) threshold as the BA to determine whether a tag/schedule materially impacts a flowgate and should be curtailed.

The MO CAT will communicate any curtailments/adjustments to ?? Scheduling System. If any Self-Dispatched Resources identified in NLS are required to be curtailed, MO CAT will also send the aggregate curtailment responsibility to each Resource owner for its curtailed Resources. Generator Shift Factors (GSF's) will also be provided through a viewer to the Market Participants. These may be used by the Market Participants to determine how to best modify their Self-Dispatch Resource schedules while still maintaining the total level of reduction required.

The MO CAT will run automatically, at least once every hour, and will produce solutions that will be communicated to RTO_SS. CAT will also run at the beginning of the next Dispatch Interval immediately following a Congestion Management status change.

As warranted, the MO CAT will also receive from the UFMP the re-load amounts for Market Flows as a flowgate starts to become unconstrained. MO CAT will use this information to re-load any curtailed or adjusted schedules.

Internal Flowgates

If the EIM component is positive and is not sufficient to achieve the required Market Flow relief, MO will reduce the EIM and then curtail and/or adjust schedules, both in order of priority, to provide the required relief.

If the net EIM component is negative, MO will curtail Schedules so that the net negative EIM impact on the flowgate is eliminated and the requested relief is achieved. Market Operator will increase the UFMP or MO Congestion Management level as necessary up to and including Level 5.

External Flowgates

If the EIM component is positive and is not sufficient to achieve the required Market Flow relief, MO will reduce the EIM and then curtail and/or adjust schedules, both in order of priority, to provide the required relief.

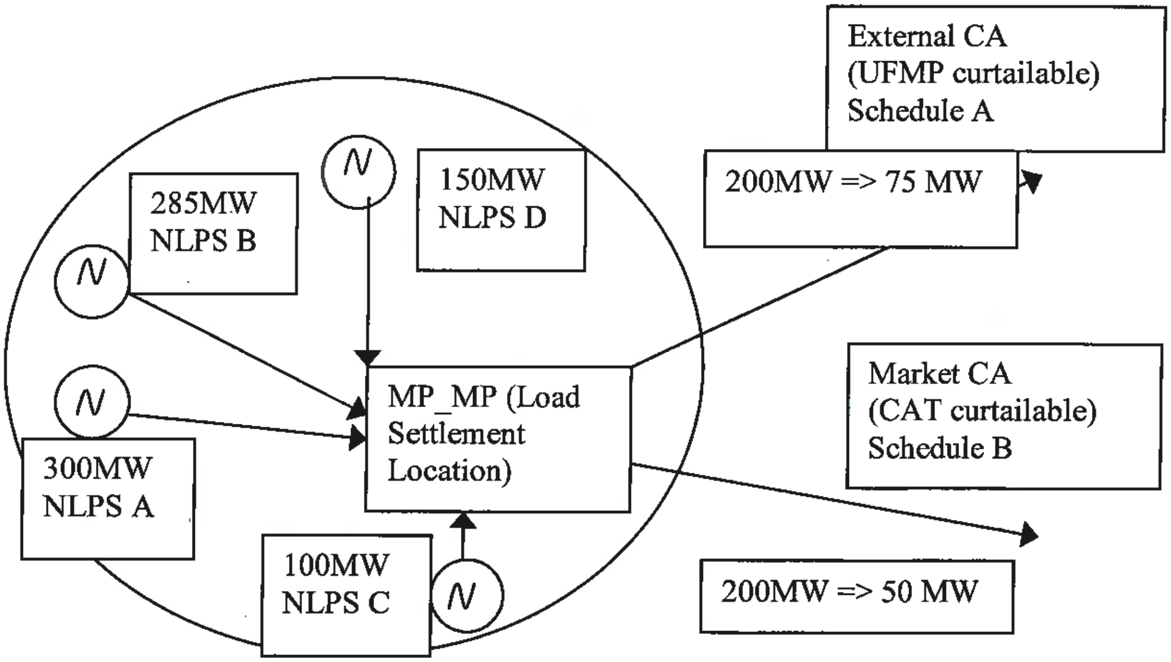
If the net EIM component is negative, MOSchedules will be curtailed so that the net negative EIM impact on the flowgate is as close to zero as possible. MO schedules will only be curtailed up to and including the UFMP level declared by the external entity that manages the flowgate. In the event MO is unable to remove all negative EIM impacts through schedule curtailments, this may result in a revenue neutrality shortfall.

In all cases, it is MO's responsibility to achieve the required Market Flow relief.

6.8.7 NLPS Tool Adjustments for Curtailments

Note: As above, this section may require updates to reflect recent and pending changes to UFMP procedures and the future implementation of WECC's Enhanced Curtailment Calculator (ECC).

Option 1
Only the NLS components of the NLPS are sent to the MFC and CAT. Following any curtailment or adjustment of Portfolio Schedules by the UFMP or CAT, the NLPS Tool will automatically adjust the NLPR components of the NLPS. This action will result in an overall adjustment to the total NLPS submitted for the Resource and will be accounted for in integrated schedule amount forwarded to Market Settlement. The following example shows the results of a curtailment scenario for the example in Section 6.6.3.3.



In this example, the two Portfolio Schedules are curtailed to 150 and 175 MW respectively. That results in a total PS curtailment of 75 MW. The curtailment will first be applied based on the normalized factors and then if necessary to the Manual NLPR. Since the lowest priority group is priority 2, the automatic NLPR in that group will be reduced first. The total in that group is 50 MW resulting in adjustment to 0 for both. The remaining 25 MW of adjustment would be made to NLPS A. To prevent the curtailment process from potentially putting a Market Participant in a position of having a total NLS component larger than its Native Load, the NLS component will not be adjusted by the NLPS Tool for curtailments of PS. This will result in the total NLPS for each Resource being reduced for the period of the curtailment.

Resource	Capacity	Submitted NLPS	NLPR (Manual)	Total Portfolio Schedules	Participation Factor %	Prioritization Identifier	NLPR (Automatic)	NLS (NITS)
A	300	300			100	1	275	210
B	400	285			70	2	0	225
C	100	100			100	2	0	
D	200	150	50		0		0	100
Total	900	735	50	400=>325			75	535

Adjustments initiated by the Purchasing Selling Entity will not be considered as curtailments. Any adjustment of PS or NLPS submitted by the Participant would trigger recalculation of the components against the scheduled amounts and a curtailment routine for NLPR would follow if PS schedules are still being curtailed for UFMP.

6.8.8 MO Congestion Management Curtailment/Adjustment Notification

For schedules/tags during a CME that are exclusively curtailed/adjusted by CAT, MO will notify the Market Participants ~~by OASIS and XML within 10 minutes~~ through the Automated Dispatch System (ADS) by 2.5 minutes before the affected dispatch interval of the schedule~~s/tags~~ adjustments ~~of~~ due to the constraint, and the shadow price of the flowgate responsible for the curtailment will be available on OASIS. For UFMP events, existing notification process continues. For MO Congestion Management metrics and reporting, both CME and UFMP events shall be reported.

7 Feasibility Studies

By the top of every Operating Hour, MO will provide results of a supply adequacy analysis for the next Operating Hour (for example, results for Hour Ending 1300 will be available by 1100).

This information shall be submitted via the OASIS website or Application Program Interface (API) Notification.

7.1 Supply Adequacy

The supply adequacy analysis will be based on Load forecast information, Resource Plans, Ancillary Service Plans, and schedules received from Market Participants. MO will determine each Market Participant's Energy Obligation. A Market Participant's Energy Obligation shall be computed as follows:

Load forecast + scheduled sales – scheduled purchases

MO will compare the Market Participant's Energy Obligation against the sum of its Max Dispatchable-MW and the sum of its Min Dispatachable-MW calculated from its Resource Plan and Ancillary Service Plan as defined in Section 8.4 of these Protocols. A Market Participant shall be deemed as having insufficient energy supply if the following condition is met:

sum of Max Dispatchable-MW < Energy Obligation

A Market Participant shall be deemed as having too much energy supply if the following condition is met:

sum of Min Dispatchable-MW > Energy Obligation

If either condition is met, the Market Participant is deemed to have inadequate supply. MO will then compare the aggregation of the Market Participants' Resource Plans and schedules by each Balancing Authority Area within the EIM Market footprint against MO's Load forecast and Ancillary Service requirements for each Balancing Authority Area. If this analysis indicates that a particular Balancing Authority Area has inadequate supply, MO will notify the Market Participant(s) deemed inadequate and its host Balancing Authority. This information shall be submitted via the Portal or Application Program Interface (API). The Market Participant shall resolve this energy supply inadequacy by modifying its Load Forecast, Resource Plan and/or schedules. The Market Participant shall make the appropriate modifications by 1700 day prior to the OD for any energy supply inadequacy revealed by the daily study. The Market Participant shall make the appropriate modifications no later than 45 minutes prior to the Operating Hour (OH) for any energy supply inadequacy revealed by the hourly study. MO shall provide a copy of any modified Resource Plans and/or schedules to the affected Balancing Authorities.

In the event a Market Participant does not resolve the issue and it contributes to a reliability problem at or prior to real-time, the BA and WECC will take appropriate actions regarding the Market Participant including interruption of Load, interruption of Resources, curtailment of schedules and or manual deployment of Resources, if deemed necessary.

8 Inadvertent Management

MO shall maintain inadvertent accounts and administer inadvertent payback for all balancing areas participating in the market. In doing so, MO shall adhere to the following principles:

1. Inadvertent payback shall be administered in accordance with NERC/WECC criteria, applicable Joint Operating Agreements, and Good Utility Practice;
2. Inadvertent payback decisions shall be made without regard to possible profits or losses resulting from changes in energy costs over time.

8.1 Management of pre-Market Inadvertent Balances

Until the beginning of the market, each Balancing Authority Area is responsible for the management of their accumulations and are expected to adjust their balances as close to zero as possible. Starting the month prior to the market, MO will verify and monitor accumulated inadvertent account balances. MO will encourage individual Balancing Authority Areas with inadvertent to schedule payback between member Balancing Authority Areas during that month prior to the market. Balancing Authority Areas should continue to perform needed Balancing Authority Area interconnect meter corrections to the inadvertent account balances.

Following the start of the market, MO will facilitate the reconciliation and payback of pre-market balance accumulations using the following steps:

Step 1 – Verify Account Balances

MO staff will manually verify the accumulated inadvertent balances (On and Off peak) for the hour prior to market implementation. These previously accumulated inadvertent account balances will be kept in accounts that will be accounted for separately from market Inadvertent accounts

Step 2 - Schedule inadvertent payback

MO will schedule, in consultation with the Balancing Authority Areas, inadvertent payback between member Balancing Authority Areas or between a member Balancing Authority Area and the applicable interconnection. Interchange Schedules for payback will be run in real-time. Payback schedules will be created by MO and included in the energy market dispatch, creating an obligation for the payback schedule on the applicable Balancing Authority Area. Payback will only be initiated when there is sufficient dispatch range available for dispatch to service the payback schedule. After the schedules have been run and checked out the schedules will be passed to the energy market settlement process, and removed from Balancing Authority Area energy accounting to allow actual adjustment to Inadvertent.

For reliability purposes, inadvertent payback will be limited to the Balancing Authority Area Lsub10. On and Off peak balances will be maintained separately. Inadvertent payback schedules can be halted at the discretion of the Reliability Coordinator or the Balancing Authority Area for reliability reasons.

Inadvertent payback of pre-market accumulations will continue until each Balancing Authority Areas has reached zero.

8.2 Management of post-Market Inadvertent Balances

There will be no inadvertent within the MO market. All deviations from schedules with Market Participants will be settled financially.

8.3 Post-market Implementation Inadvertent Accounting Steps:

Step 1 – Set up new inadvertent account balances

MO will set up new inadvertent account balances for each Balancing Authority Area beginning with hour one of the market implementation.

Step 2 - Settle inadvertent account balances financially

Inadvertent for post-Market operation will be maintained and managed by the MO. Each hour each Balancing Authority Area will calculate its contribution to the MO Inadvertent accumulation for the hour by subtracting the Net Actual Interchange (NAI) from the Net Schedule Interchange (NSI). These figures will be calculated by each Balancing Authority Area and reported to the MO each hour. MO will sum all of the MO Balancing Authority Area figures to arrive at the MO inadvertent accumulation for that hour.

Step 3 - Schedule MO Inadvertent Payback

MO will manage MO inadvertent payback with the applicable interconnection. Payback obligation will be created by MO and included in the energy market dispatch, creating an obligation for the payback on the energy market. Payback will only be initiated when there is sufficient dispatch range available for dispatch to service the payback schedule.

8.4 Inadvertent Payback Reporting

The MO will report its Inadvertent Interchange balance with the applicable interconnection. MO reporting will be consistent with the requirements and timelines for Balancing Authorities outline in NERC Reliability Standard BAL-006-0. In addition MO will maintain records of Inadvertent Interchange financially settled with each Balancing Authority Area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

The MO will manage and pay back its post market net Inadvertent Interchange balance following NAESB WEQBPS-005-000 Inadvertent Interchange payback Inadvertent will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms. Inadvertent payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover inadvertent interchange.

8.5 Uninstructed Deviation

Uninstructed Deviation is the difference in the Dispatch Instruction and the real time operating level as indicated via SCADA for the Resource. Resources that choose financial settlement based on energy delivered in each dispatch interval, with separately price calculations for instructed and uninstructed energy, may be deemed to be settled using cost-based LIPs, and therefore not subject to uninstructed deviation charges. Resources that choose financial settlement based on hourly energy delivery have less financial incentive to respond to changes in system conditions within an operating hour, and therefore are subject to uninstructed deviation charges as described in this section 8.5. MO will calculate and retain the Uninstructed Deviation at the end of each Deployment Interval based on MO's clock synchronized to True Time GPS Satellite.

8.5.1 Resource Operating Tolerance

A Resource operating tolerance will be defined based on an acceptable amount of dispatching error with an adjustment for regulation services being maintained on the Resource. The operating tolerance is intended allow the MO to maintain the efficiency of the EIM dispatch and provide additional financial incentives for Market Participants to cause their Resources to perform, whether offered for MO Dispatch or Self Dispatched, within an acceptable range. The portion of the operating tolerance based on the Resource's Capability will be the acceptable dead band percentage multiplied by the MaxEconMW and limited to a minimum of 5 MW and maximum of 25 MW. A Resource will be considered to be operating within acceptable Resource operating tolerance so long as its current operating level is between the high and low operating tolerance limits defined as follows:

$$RH_i = \text{Max}\ (5, \text{Min}\ ((MaxMW_i\ * DBP), 25)) + REGUP_o$$

$$RL_i = \text{Max}\ (5, \text{Min}\ ((MaxMW_i\ * DBP), 25)) + REGDN_o$$

Where:

RH= Resource High operating tolerance or over generation limit (MW)

RL= Resource Low operating tolerance or under generation limit (MW)

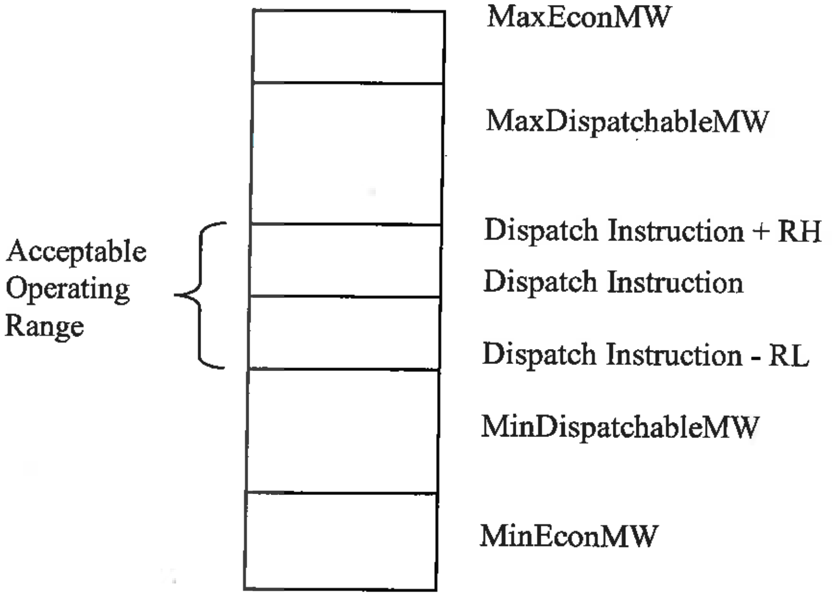
MaxMW = Maximum Capacity Operating Limit - Resource physical maximum sustainable output for each Operating Hour from Resource Plan.

DBP = Dead Band Percentage for all Resources is initially set to 10 % above and below the Max Econ MW of the Resource (MaxEconMW), but is subject to change by subsequent Protocol Revision Request. .

REGUP_0 = Regulation Up service being maintained on the Resource as indicated in the Ancillary Service Plan (MW) for the Operating Hour.

REGDN_0 = Regulation Down service being maintained on the Resource as indicated in the Ancillary Service Plan (MW) for the Operating Hour.

i = Dispatch interval within Operating Hour.



8.5.2 Uninstructed Deviation Charge Calculations

In addition to the settlement for EIM, Uninstructed Deviation Charges will be assessed to any Resource that operates outside the defined Resource operating tolerance. A Resource operating outside the tolerance will incur a charge based on the amount the Resource is outside the operating tolerance and a percentage of the LIP for the applicable hour with the charge increasing with the amount of uninstructed deviation. The calculation of the charge shall be as follows:[2]

$$\text{UDC} = \text{ABS}\left(\left(\text{Min}\left(\text{UDMW}, 25\right) * 10\,\% + \left(\text{Max}\left(0, \text{UDMW} - 25\right) * 25\,\%\right)\right) * \text{LIP}_o\right)$$

$$\text{UDMW} = \left(\sum_{i=1}^{12} \text{ABS}\left(\text{Max}\left(\text{Max}\left(0, \text{ARP}_i - \left(\text{EOL}_i + \text{RH}_i\right)\right), \text{Max}\left(0, \left(\text{EOL}_i - \text{RL}_i\right) - \text{ARP}_i\right)\right)\right) / n\right)$$

Where:

UDC = Uninstructed Deviation Charge calculation per hour for each Resource

UDMW = Average absolute MW deviation outside the operating tolerance for all intervals in the hour.

RH = Resource High operating tolerance or over generation limit (MW) as defined in Section 8.5.1 for the interval.

RL = Resource Low operating tolerance or under generation limit (MW) as defined in Section 8.5.1 for the interval.

ARP = Actual Resource Production at the end of the Dispatch Interval.

EOL = Expected Operating Level for the Dispatch Interval.

LIP = Locational Imbalance Price for the Operating hour and Resource Settlement Location.

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[2] As noted elsewhere, the CAISO does not currently use an Uninstructed Deviation Charge other than settlement of real-time at the resource location's LIP. The CAISO has also proposed limitations on bid cost recovery payments based on deviations. The need for and structure of an Uninstructed Deviation Charge is among the implementation details that should be the subject of EIM stakeholder discussions.

i = Dispatch interval within Operating Hour.

o = Operating Hour

n = Number of intervals in an Operating Hour or twelve (12).

The Uninstructed Deviation Charge is anticipated to be an interim measure until a regulation ancillary service market is established and including alternative performance incentives.

Example 1

Generator A is available for MO Dispatch
600 Maximum Capacity Limit
250 Minimum Capacity Limit
5 MW Regulation Up from the Ancillary Service Plan
5 MW Regulation Down from the Ancillary Service Plan
100 Scheduled Amount from Settlement Location associated with the Resource.
$55 Locational Imbalance Price for the hour

Time	Dispatch Instruction	Actual SCADA Operation	RH	RL	UD	UD Outside Range
1205	500	450	30	30	-50	20
1210	500	460	30	30	-40	10
1215	500	475	30	30	-25	0
1220	500	490	30	30	-10	0
1225	500	500	30	30	0	0
1230	500	510	30	30	10	0
1235	500	530	30	30	30	0
1240	500	545	30	30	45	15
1245	500	530	30	30	30	0
1250	500	505	30	30	5	0
1255	500	500	30	30	0	0
1300	500	505	30	30	5	0
						3.75 UDMW
						$20.63 UDC

Example 2

Generator A is Self Dispatched

600 Maximum Capacity Limit
250 Minimum Capacity Limit
0 MW Regulation Up from the Ancillary Service Plan
0 MW Regulation Down from the Ancillary Service Plan
5 Ramp Rate reported on the Resource Plan
300 Scheduled Amount from Settlement Location associated with the Resource for each interval.
$55 Locational Imbalance Price for the hour

Time	Dispatch Instruction	Actual SCADA Operation	RH	RL	UD	UD Outside Range
1205	300	310	25	25	-10	0
1210	300	320	25	25	-20	0
1215	300	330	25	25	-30	5
1220	300	340	25	25	-40	15
1225	300	350	25	25	-50	25
1230	300	360	25	25	-60	35
1235	300	520	25	25	-220	195
1240	300	535	25	25	-235	210
1245	300	520	25	25	-220	195
1250	300	505	25	25	-205	180
1255	300	500	25	25	-200	175
1300	300	495	25	25	-195	170

100.416667 URMW
$1,174.48 URC

8.5.3 Uninstructed Deviation Calculations during Reserve Sharing Events

For Resources carrying spin and non-spin capacity, the uninstructed deviation incurred during an MO Automated Reserve Sharing event will be set to zero for the purposes of determining uninstructed deviation.

8.5.4 Intermittent Resources

The difficulty in predicting the actual output of intermittent Resources makes it difficult to predict their actual operating level for the end of each Dispatch Interval and makes such Resource's ability to respond to Dispatch Instructions limited. As a result Intermittent Resources may take the following action in order to minimize the error unpredictable operation introduces into the MO market dispatch as well as minimize their exposure to Uninstructed Deviation Charges.

The Market Participant will indicate the Resource is Market Dispatched with a minimum and maximum capability reflecting the limitations of the Resource and a ramp rate of zero (0) MW per minute.

MO will begin generating Dispatch Instructions consistent with the information provided and as a result Dispatch Instructions will equal the operating level of the Resource at the time of the dispatch calculations for the Dispatch Interval. While Resource actual operation during the

Dispatch Interval is expected to vary based on the actual conditions, the Resource will not be subject to Uninstructed Deviation Charges based on these Dispatch Instructions.

8.5.5 Other Grounds for Exemption

Resources shall not be subject to Uninstructed Deviation Charges for any Uninstructed Deviation Megawatts caused by: (1) Manual Dispatch Instructions (2) redeployment by the Balancing Authority (3) Test Mode; or (4) Start-up or Shut-down Mode of either a Resource or each generating unit individually if multiple generating units are registered collectively as a single Resource; or (5) Instances when a Resource trips or is derated after receiving Dispatch Instructions (6) the Resource is an Intermittent Resource; or (7) the dispatch instructions issued to a Resource were beyond the reported capabilities in the Resource Plan due to the application of a VRL.[3]

The Market Operator may also waive Uninstructed Deviation Charges to the extent a Market Participant can demonstrate such deviation was caused solely by events or conditions beyond its control, and without the fault or negligence of the Market Participant. The Market Participant must provide the Market Operator with adequate documentation through the invoice dispute process in order for the Market Participant to be eligible to avoid such Uninstructed Deviation Charges. The Market Operator shall determine through the dispute process whether such Uninstructed Deviation Charges should be waived.

Uninstructed Deviation Penalty exemptions will be granted automatically for any hour during which a Market Participant has utilized the Start-up / Shut-down Indicator in the Resource Plan. However, MO shall monitor the use of this indicator for any of the following items as appropriate:

- Plan MW less than Min MW as a start-up indicator;
- Substantial changes in Min MW and Max MW from one hour to the next, or intra-hour, that are indicative of generating unit start-ups and shut-downs. Market Participants should provide MO with information regarding the typical minimum size of Min MW and Max MW changes to expect when unit start-ups and shut-downs occur for a Resource; and
- SCADA data at the individual unit levels, changing from zero to non-zero or non-zero to zero, value

If these items are not found during, before or after the hour in which the Start-up / Shut-down Indicator in the Resource Plan is selected, MO will disallow the Market Participant's exemption from UD Penalties during such hour. The Market Participant may then avail itself of the settlement dispute process to supply additional information to MO to contest the exemption denial. Upon review of such information, by MO, it may reinstate the exemption from the UD

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[3] Intermittent Resources that bid into EIM are exempt from Uninstructed Deviation Charges other than normal settlements of imbalance energy, but do not become eligible for the CAISO's Participating Intermittent Resource Program (PIRP).

Penalties for the Market Participant for such hour, if MO determines that a UD Penalty exemption was appropriate.

8.5.5.1 Exception Request Documentation

If the Balancing Authority redeploys a unit it shall provide documentation justifying that redeployment to the and the Market Monitor. Market Operator and the Market Monitor shall investigate and review the documentation and determine if the appropriate action was taken.

8.5.6 Uninstructed Deviation Charge Payment

The Uninstructed Deviation Charges from Resources will be uplifted though Revenue Neutrality Uplift Procedure as in found in Section 9.

9 Deployment

9.1 Introduction

Market Operator shall determine the least costly means of obtaining energy to serve the next increment of Load at each injection/withdrawal node and each interface with each adjacent Balancing Authority Area. Each injection/withdrawal node is defined in the State Estimator for the MO Market Footprint. Each potential transmission constraint within the MO Market footprint, transmission facilities in the MO Market footprint that affect flows on these constraints, and each interface with each adjacent Balancing Authority Area, as well as significant network topology and representations of sources and sinks within each adjacent Balancing Authority Area, are modelled in detail in the MO's State Estimator. To ensure coordination between the MO's market functions and the WECC RC's reliability functions, the MO's State Estimator exchanges solutions with the WECC RC's state estimator, and incorporates data from the WECC RC's state estimator when it can enhance the quality of the MO's State Estimator solution. The least costly means of obtaining energy is calculated by the Scheduling, Pricing, and Dispatch (SPD) program. The following limiting factors are utilized by SPD:

- The system conditions described by the most recent power flow solution produced by the State Estimator program;
- Resource parameters provided in Resource Plans and Ancillary Service Plans;
- Energy Offer Curves;
- Activated transmission constraints

In certain situations, enforcing all such limiting factors may result in a solution that is not feasible at a shadow price less than an appropriately priced VRL. In such cases, MO must apply Violation Relaxation Limits (VRLs) in SPD.

SPD uses an incremental linear optimization method to minimize energy costs and assumes Self Dispatched Resources will be operating at their scheduled Megawatt level indicated on the ?? Scheduling System schedules, including NLPS, at the end of each Dispatch Interval.

Deployment calculated by SPD determines the Dispatch Instructions for Resources that have offered to provide EIM. The Resource Dispatch Instructions are based upon the Offer Curve, Resource Plan, and Ancillary Services Plan. Resources that have elected to be dispatched by MO will have:

- The entire MW capability available for MO dispatch, subject to the MaxEconMW, MinEconMW;
- Ramp Rate and Ancillary Service parameters specified by the Market Participant in the Resource and Ancillary Service Plans.

9.1.1 Application of VRLs

When necessary to avoid excursions in shadow prices and to ensure a programmatic solution in all cases, SPD applies VRLs.[4] A higher VRL value is an indication of the relative priority for enforcing the constraint type. For example, the VRL value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. If the VRL with the lowest value will not allow SPD to balance the market's energy obligations, a higher VRL will be applied. In the case of the Operating Constraint VRL, the value limits the cost of the dispatch needed to balance system injections and withdrawals by capping the shadow price.

The four categories of VRLs are:

- Operational Constraints (OCs); subcategories being:
  - Flowgate constraints
  - RTCA constraints
  - Watch list constraints
  - Manual constraints
  - PNode constraints
- Resource ramp rate limits
- Market balance (generation to load)
- Resource capacity maximum/minimum output limits

When an OC limit is reached but not exceeded, it is referred to as "binding." In this state, VRLs are not applicable.

Market Operator shall provide a standard ~~XML~~ market notification via programmatic interface to all Market Participants for each instance that the MO implements a VRL. All VRL notifications

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[4] VRLs are equivalent to constraint parameters that are documented in the CAISO's Business Practice Manual for Market Operations, section 6.6.5.

shall identify the type of limit relaxed/VRL category, the MW amount of relaxation, and the associated flowgate or Resource name. The Resource name will only be provided to the Market Participant to whom the Resource is registered and will not be provided to all other Market Participants.

VRLs and associated values are intended to achieve the following objectives:
(1) Mitigate the occurrence of price excursions or other extreme prices;
(2) Remove the portion of a loading violation attributed to market flow on a flowgate within 30 minutes of the start of a VRL violation;
(3) Mitigate the regulation burden placed on the Resources providing regulation services;
(4) Limit contribution to CPS violations; and
(5) Minimize the need for Manual Dispatch Instructions

9.1.2 Impact of VRLs on LIPs and Uninstructed Deviation Charges

The VRL value applied by SPD is not used directly in determining the LIP for any Resource. LIPs are determined by the Resource Dispatch Instructions issued by MOS.

In the event that a Dispatch Instruction resulting from the application of a VRL violates a Resource Plan parameter, Uninstructed Deviation Charges (UDC) shall not be applied.

9.1.3 Determination of VRLs

Each year by November 1, VRLs and their associated values shall be reviewed and approved by the XXXX based on recommendations received from XXXX and XXX. Any changes to the VRLs or associated values must be approved for filing by the Board of Directors and approved by FERC prior to their implementation. The most recent FERC approved VRLs and their associated values shall be posted on the OASIS website.

9.1.4 VRL Reporting

By August 1st each year, MO will provide analysis as well as a set of proposed VRLs and associated values to the XXXX and XXX. XXXX and XXX will then recommend a set of proposed VRLs and associated values to the XXXX.

9.1.4.1 *Quarterly Metric Reporting*

Market Operator shall report the following information to the XXXX and the XXX on a quarterly basis in the month following the end of the quarter:

a. A summary report and supporting detailed data identifying:

- Number of times, each month, the application of VRL was required to provide a market solution
- VRL type and value
- Amount of the limiting condition
- Amount exceeding the limit
- Resulting shadow prices for each incident

- Number and duration of each incident where a VRL was employed with respect to the same flowgate for six or more consecutive intervals
- Number and magnitude of manual dispatch instructions issued coincident with the application of a VRL

b. An assessment of how effective the VRLs have been at achieving the stated objectives.

9.1.4.2 *Annual Reporting*

Each year by August 1st, MO shall produce a report with supporting documentation that will analyze the effectiveness of VRLs and associated values on reliability and prices. The report shall include a sensitivity analysis of the existing VRL and associated values and examine impacts of raising or lowering the associated values. If changes are warranted, MO shall recommend changes to the XXXX and the XXX for consideration.

9.2 Content

9.2.1 Dispatch Instruction

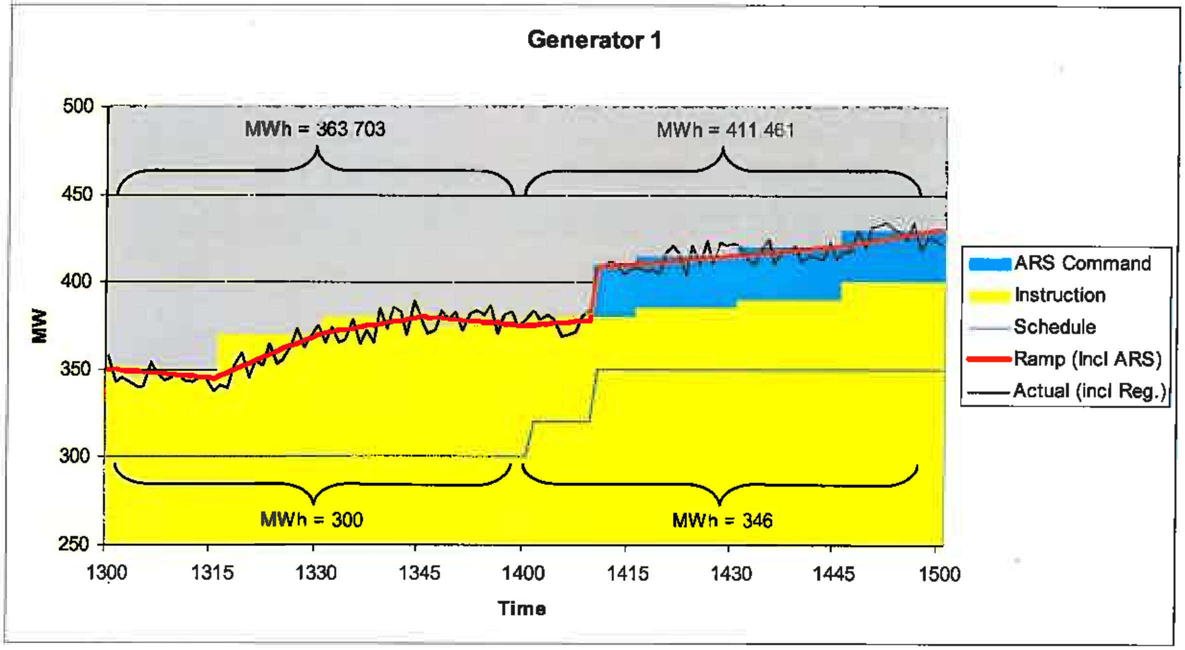
The dispatch instruction is a MW set-point for the end of the Deployment Interval. They are sent to every Resource in the Market Footprint for every interval. The Dispatch Instruction is determined differently depending on the Status of the Resource in the Resource Plan. Details for this are described in Section 9.4 Use of Data. The following items, however, make up the components of every Dispatch Instruction.

- Resource Name
- Resource Type (GEN, PLT, CLD)
- Date
- Interval Ending (HH MM)
- Dispatch Type (EIM, other)
- MW set-point
- Price $/MWH

For JOUs, the MO shall develop an aggregate dispatch instruction to be sent via ICCP representing the total of all dispatch instruction for each JOU co-owner. This aggregate dispatch instruction shall consist of the following:

- Resource Name per each JOU co-owner's registration
- MW set-point

In the example below, the Resource has both scheduled energy and offered into the imbalance market. Every 5 minutes a new dispatch instruction is sent (represented by the yellow area) and the Resource is ramping to achieve the dispatch (represented by the red line). Regulation results in the Resource moving around the ramp (represented by the black line).



Note that the schedules (represented by the blue line) are not the same thing as dispatch instructions. The schedules also change when reserve deployment occurs (shown as the cyan area and an increase in the blue schedule line). The integrated MWh from the actual performance and the schedules are reflected for hours ending 1400 and 1500. An imbalance payment would result from the above example for both hours, regardless of the regulation down impacts. The impact of reserve deployment is offset by the change from the net scheduled amount, resulting in no increase in imbalance. Reserves are settled through the reserve sharing agreement.

Market Operator's dispatch instruction may exceed the Ramp Rate in the Resource Plan for a particular Resource under the following conditions:

- A Resource ramp rate VRL is triggered for the market footprint; or
- A parameter in a Resource Plan or Ancillary Service Plan is modified such that the change in the Dispatchable Range of the Resource, from one Deployment Interval to the next, is greater than the Ramp Rate capability.

Where a constraint has been bound on a transmission line and market units redispatched to limit flow across that line, MOS will not release the bound constraint until such time as the flow on the line has been reduced, by an amount determined by MO no greater than x on a flowgate by flowgate basis, of the total line limit. Delaying release of the bound constraint is designed to prevent oscillating dispatch up and dispatch down instructions on the marginal unit impacting the line.[5]

9.2.1.1 Uninstructed Deviation

Uninstructed Deviation is the difference between the dispatch instructions and the actual performance of the Resource. Uninstructed Deviation is calculated for all Resources. The difference is calculated for the end of each Deployment Interval. These differences are captured for integration purposes and further analysis.

Uninstructed Deviation vs. Imbalance Example 1

Generator A is available for SPP deployment

Schedule for hour ending 1300:
Generator A to Load A 100 MWh

Time	Schedule	Dispatch Instruction	Instantaneous Measurement	Uninstructed Deviation	Settlement Measurement
1215	100 MW	100 MW	85 MW	-15 MW	
1230	100 MW	120 MW	129 MW	9 MW	
1245	100 MW	110 MW	130 MW	20 MW	
1300	100 MW	100 MW	100 MW	0 MW	
					110 MWh

Imbalance = (Actual MWh - Scheduled MWh)
Imbalance = (110 MWh - 100 MWh) = 10 MWh surplus

Uninstructed Deviation vs. Imbalance Example 2

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[5] The CAISO makes similar adjustments to conform transmission limit margins to maintain reliability.

Generator A is available for SPP deployment

Schedule for hour ending 1300:
Generator A to Load A 100 MWh

Time	Schedule	Dispatch Instruction	Instantaneous Measurement	Uninstructed Deviation	Settlement Measurement
1215	100 MW	125 MW	110 MW	-15 MW	
1230	100 MW	125 MW	110 MW	-15 MW	
1245	100 MW	125 MW	110 MW	-15 MW	
1300	100 MW	125 MW	110 MW	-15 MW	
					110 MWh

Imbalance = (Actual MWh - Scheduled MWh)
Imbalance = (110 MWh - 100 MWh) = 10 MWh surplus

9.2.2 Out of Merit Energy (OOME)

Market Operator, in coordination with BA, may dispatch any Resource through manual processes only where necessary to resolve Emergency conditions that the EIM market through SCED cannot resolve. Market Operator will issue manual instructions (referred to in the system as "OOME," or out of merit energy) at the MW level the resource is expected to produce until such time as an appropriate constraint can be recognized by MOS and BA. Market Operator, in coordination with BA, will make every effort to define and activate the constraint in MOS within one hour of the manual reconfiguration. The reliability issues identified by the Balancing Authority and/or WECC, with solutions, will be coordinated with the MO for the purpose of the MO incorporating into the deployment of any Resource, whether through SCED or manual processes.

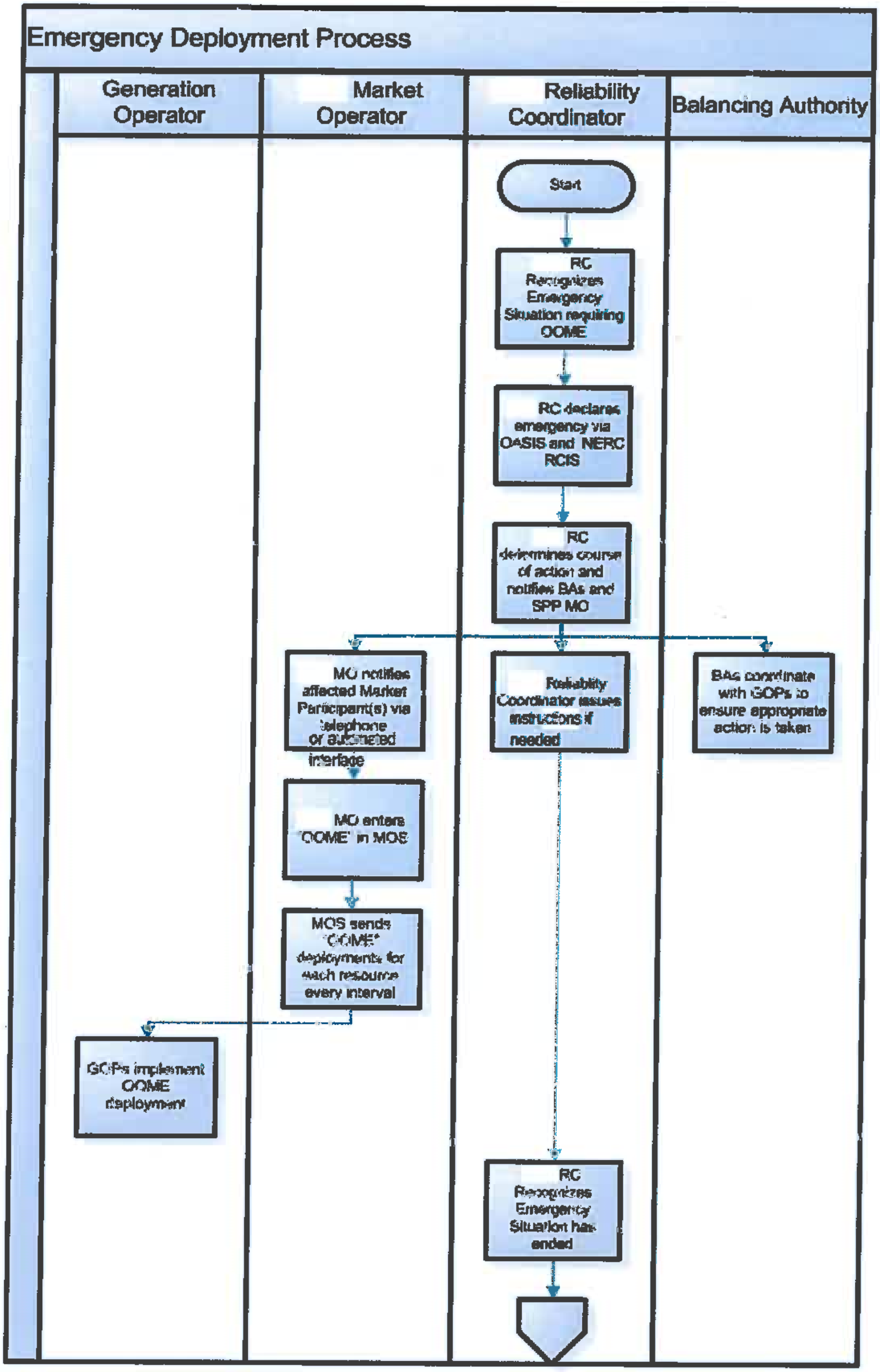
When an OOME is created notifications will immediately be issued for all future intervals for which an EIM Dispatch Instruction has already been sent. The OOME notification for future intervals not yet dispatched will be sent directly following the EIM Dispatch Instruction for those intervals. So Market Participants will receive an OOME Dispatch Instruction for each interval that supersedes the EIM Dispatch instruction for the same interval

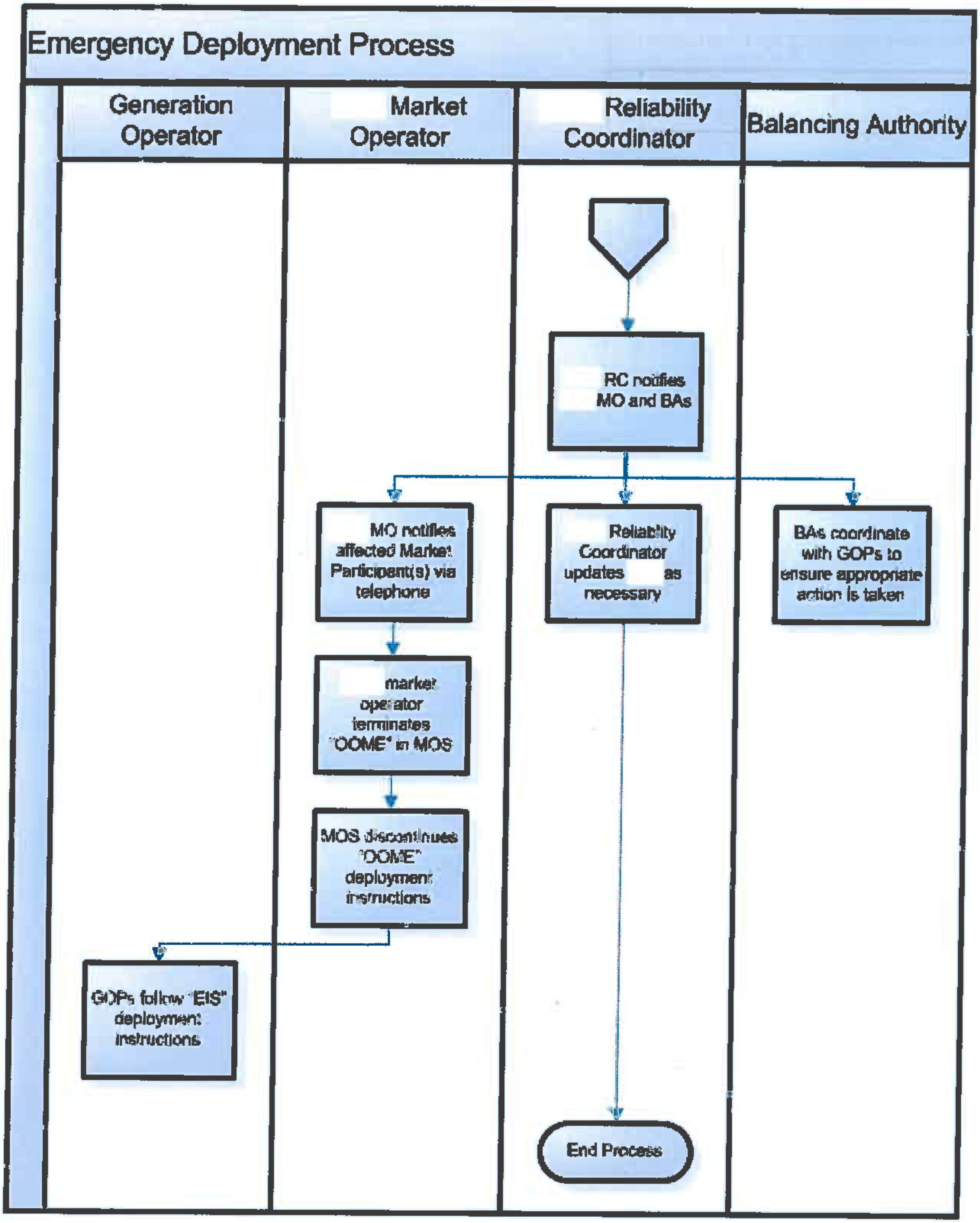
More than one OOME may be initiated for the same Resource within a given interval. In such a case the OOME instruction indicating the latest timestamp will be utilized.

The end of an OOME event will be noted by the absence of an OOME notification.

Uninstructed Deviation will be automatically waived and Uninstructed Deviation Charges will not be assessed for a Resource for each interval it receives an OOME instruction consistent with section 8.5.6.

Below is an overview of the OOME communication process in instances in which the WECC Reliability Coordinator identifies situations requiring use of OOME.


Emergency Deployment Process
Generation Operator
Market Operator
Reliability Coordinator
Balancing Authority
Start
RC Recognizes Emergency Situation requiring OOME
RC declares emergency via OASIS and NERC RCIS
RC determines course of action and notifies BAs and SPP MO
MO notifies affected Market Participant(s) via telephone or automated interface
Reliability Coordinator issues instructions if needed
BAs coordinate with GOPs to ensure appropriate action is taken
MO enters "OOME" in MOS
MOS sends "OOME" deployments for each resource every interval
GOPs implement OOME deployment
RC Recognizes Emergency Situation has ended


Emergency Deployment Process
Generation Operator
Market Operator
Reliability Coordinator
Balancing Authority
RC notifies MO and BAs
MO notifies affected Market Participant(s) via telephone
Reliability Coordinator updates as necessary
BAs coordinate with GOPs to ensure appropriate action is taken
market operator terminates "OOME" in MOS
MOS discontinues "OOME" deployment instructions
GOPs follow "EIS" deployment instructions
End Process

9.2.3 Net Scheduled Interchange

Net Scheduled Interchange is calculated as a net of all approved inter Balancing Authority Area schedules in ?? Scheduling System and for use in additional MOS calculations. This includes schedules from NERC Tags, schedules that are a result of an Automated Reserve Sharing (ARS) event and other schedules that are created within ?? Scheduling System. Dynamic schedules are not included in the calculation of NSI.

Every 4 seconds the following occurs:

> RTO_SS will send real time NSI values to MO. The MO will sum the real time NSI from ?? Scheduling System with the EI component from Market Operations System (MOS) and send this signal to Balancing Authorities via ICCP on an approximate 4-second interval. MO shall provide a backup mechanism for MO Balancing Authority Areas to receive the EI NSI

Every 5 minutes the following occurs:

1. SCED is performed for the next 5 minute interval using four primary sets of inputs under normal circumstances.
    - The first set of inputs includes the latest generation values collected from ~~WECC~~ MO's EMS AGC (fed from ICCP).
    - The second input includes the Resource ramp rates and availability flags in effect for that interval.
    - The third input includes the Resource offers for EIM.
    - The fourth input includes Resource requirements based on the short term MO Balancing Authority Area forecast and the net of schedules flowing into or out of the market footprint (obtained from ?? Scheduling System.
2. MOS calculates the total MO NSI and Scheduling System Balancing Authority Area NSIs using the schedules that were collected from ?? Scheduling System.
    - MOS performs security constrained economic dispatch using MO NSI and Balancing Authority Area Load Forecasts for the interval.
    - The generation for each Balancing Authority Area is summed and the Balancing Authority Area Load Forecast is subtracted from that generation to calculate the Economic Dispatch NSI (ED NSI).
    - MOS subtracts the BAA NSI from the ED NSI to produce the Energy Imbalance NSI (EI NSI).
3. MOS sends the EI NSI component (one per BAA) to the BA.

9.2.4 Inadvertent Interchange

MO shall maintain inadvertent accounts and administer inadvertent payback for all Balancing Authority Areas participating in the MO market. In doing so, MO shall adhere to the following principles:

1. Inadvertent payback shall be administered in accordance with NERC/WECC criteria, applicable Joint Operating Agreements, and Good Utility Practice;
2. Inadvertent payback decisions shall be made without regard to possible profits or losses resulting from changes in energy imbalance prices over time.

9.2.5 Real-Time Deficit and Excess condition in Dispatchable Ranges

A real-time deficit condition occurs when the MO does not have adequate dispatchable resources to meet real-time imbalance energy demand. A real-time excess condition occurs when the MO is unable to meet real-time imbalance energy demand without violating the minimum dispatchable range of dispatchable resources. ~~Market Operator shall address these conditions by adjusting the NSI values of that Balancing Area(s) where the Market Participant causing the deficit or excess condition.~~

9.2.5.1 Identification of MP causing Deficit or Excess condition

In the intra-operating day capacity adequacy tests performed for each operating hour, MO shall evaluate all MP's forecast load and the sufficiency of offered EIM resources. MO will estimate each MP's real-time EIM demand based on the information available at the time these checks are performed. MO shall also evaluate whether each MP has arranged for adequate capacity to meet their real time load obligation, if any.

MPs within that BA(s) shall be notified that an excess or deficit condition exists within the BA, and MO will assist the BA to maintain reliable operations. BA(s) shall coordinate with MO all action necessary according to Attachment XX of the OATT.

9.2.5.2 Declaration of Deficit condition

Market Operator shall evaluate, on a forward looking basis, at the time it calculates the dispatch instruction for the applicable dispatch interval, whether it is able to meet the EIM demand of the Market footprint for that dispatch interval. If MO determines that it is unable to meet the anticipated EIM demand for that dispatch interval because of a lack of deliverable EIM resource(s), it will declare a deficit condition for the EIM Market. At this time, MO shall also determine which Balancing Areas are specifically deficient. Market Operator shall post a notification to all BAs of the Market deficit condition. Market Operator shall also send notice of deficit conditions to all MPs within the deficient BA(s).

9.2.5.3 Declaration of Excess condition

Market Operator shall evaluate, on a forward looking basis, at the time it calculates the dispatch instruction for the applicable dispatch interval, whether it is able to meet the EIM demand of the Market footprint for that dispatch interval. If MO determines that it is unable to meet the anticipated EIM demand for that dispatch interval because of it would have to violate the minimum dispatchable range of deliverable EIM resource(s), MO will declare an excess condition for the EIM market and notify all Balancing Areas. MO shall also identify the specific BA(s) that will be affected by the excess condition, and send notifications to all MP within those BA(s) of that excess condition.

9.2.5.4 *Data provided to BA and MP Notification*

At the time MO determines if an excess of deficit condition exists within a Balancing Area, MO shall provide the following information to the Balancing Authority.

- Dispatch Interval
- MW amount of anticipated mismatch
- MP net Schedule total and net Deployment Instructions
- Estimated ~~NSI bias amount~~ NAI projection

9.2.5.5 *~~NSI~~ NAI Adjustment*

For those Balancing Authorities where excess or deficit condition exists, an ~~NSI~~ NAI adjustment totaling the shortage or excess demand will be ~~shared pro-rata~~ determined by the Balancing Authority in real-time depending on how over or short each Balancing Area is estimated to be. MO will coordinate with the Balancing Authorities in determining the ~~NSI bias~~ NAI adjustment and BA actions to minimize the effect on reliability and the BA's ability to regulate and/or utilize spinning reserve(s), and to avoid the need to declare an OEC or EEA.[6]

9.2.5.5.1 Deficit Condition

If in real-time MO has a generation dispatch deficit, the deficit MW will be distributed among all BAs with generation shortage to be reflected in their ~~NSI~~ NAI. The adjusted BA ~~NSI~~ NAI for BAs with capacity shortage is equal to:

Total Balancing Authority Area (BAA) Resource MW (-) BAA Load Forecast (+) BAAs pro rata share of the system shortage

BA s with shortage will be identified as having a positive value for:

BAA Load Forecast (-) BAA Total Maximum Dispatchable Generation (+) BAA Net Scheduled Export

In this event, the LIP of all resources that were identified as AGC resources in the Balancing Authorities A/S plan, will be set to the highest market wide cleared offer.

9.2.5.5.2 Excess Condition

If in real-time the market has a generation dispatch excess, the excess MW will be distributed among BAs with excess energy to be reflected in their ~~NSI~~ NAI. The adjusted BA ~~NSI~~ NAI for BAs with generation excess is equal to:

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[6] The mechanisms for NAI adjustments should be determined through an EIM stakeholder process.

Total BAA Resource MW (-) BAA Load Forecast (+) BAAs pro rata share of the system excess

BAs with excess will be identified as having negative value for:
BAA Load Forecast (-) BAA Total Minimum Dispatchable Generation (+) BAA Net Scheduled Export

In this event, the LIP of all resources that were identified as AGC resources in the Balancing Authorities A/S plan will be set to the lowest market wide cleared offer.

9.2.5.6 Exemption

Any resource deployment by the Balancing Authority to mitigate any excess or deficit conditions will be exempt from Uninstructed Deviation and Over/Under-Scheduling penalties.

9.2.5.7 Post Analysis

Within 24 hours of completion of an excess/deficit condition, MO shall prepare a report to the effected BA(s) and MP(s).

9.3 Timing

Dispatch instructions are calculated every 5 minutes beginning at ~~0000~~ 2.5 minutes before the start of each Deployment Interval. The instruction is a set point for the ~~end~~ middle of the Deployment Interval and is communicated 2.5 minutes before the beginning of the Deployment Interval. This enables MO to determine dispatch instructions based on the most current system status for the Deployment Interval, while publishing binding LIPs for the Deployment Interval prior to the start of the interval. The instructions are communicated through the MO's secure network or the Internet to a listener and use XML format as the primary delivery mechanism. The MW set point portion of the instruction will also be available through an ICCP point defined for each Resource. Market Operator will communicate the ICCP Deployment Instructions through EMS. The XML instruction will be the basis for all settlement calculations and resolution of any disputes. NSI is calculated every 4 seconds and incorporates the ramping data from the Resource Plans and ?? Scheduling System. The NSI is communicated using ICCP.

The interval between the communication of a Dispatch Instruction and the beginning of the Deployment Interval will be periodically reviewed to determine whether the time lag can be reduced.

9.4 Use of Data

Data from the Offer Curves, Resource Plan, and Ancillary Services Plans are used, along with the State Estimator, to calculate the dispatch instruction. If a Resource indicates availability for MO dispatch control through the Resource Plan, the Security Constrained Economic Dispatch requests movement within the dispatchable range. For a unit in Available Quick Start status, while the Resource breaker is open, the MOS will treat the Resource just like other Resources Available for MO Dispatch with a Minimum Capacity Operating Limit of zero (0) MW. For a unit in Available Quick Start status, when the Resource breaker is closed, the MOS will treat the

Resource just like other Resources Available for MO Dispatch with a Minimum Capacity Operating Limit as indicated on the Resource Plan. This range is calculated using the data from the Resource Plan and reserve designations (a.k.a. Ancillary Service Plan), as illustrated below:

$$\text{MinDispatchableMW}_i = \text{MinEconMW}_o + \text{REGDN}_o$$

$$\text{MaxDispatchableMW}_i = \text{MaxEconMW}_o - \text{REGUP}_o - \text{MAX}\ (\text{SPIN}_o + \text{SUPP}_o - \text{RSS}_i, 0)$$

Where:

$\text{MinDispatchableMW}_i$ = Minimum Limit of Dispatchable Range (MW)

$\text{MaxDispatchableMW}_i$ = Maximum Limit of Dispatchable Range (MW)

MinEconMW_o = Minimum Economic Capacity Operating Limit (MW) as indicated on the Resource Plan for the hour of the Dispatch Interval (MW)

MaxEconMW_o = Maximum Economic Capacity Operating Limit (MW) Limit as indicated on the Resource Plan for the hour of the Dispatch Interval (MW)

SPIN_o = Spinning Reserves being maintained on the Resources as indicated in the Ancillary Services Plan for the hour of the Dispatch Interval (MW)

SUPP_o = Supplemental Reserves being maintained on the Resource as indicated in the Ancillary Services Plan for the hour of the Dispatch Interval (MW)

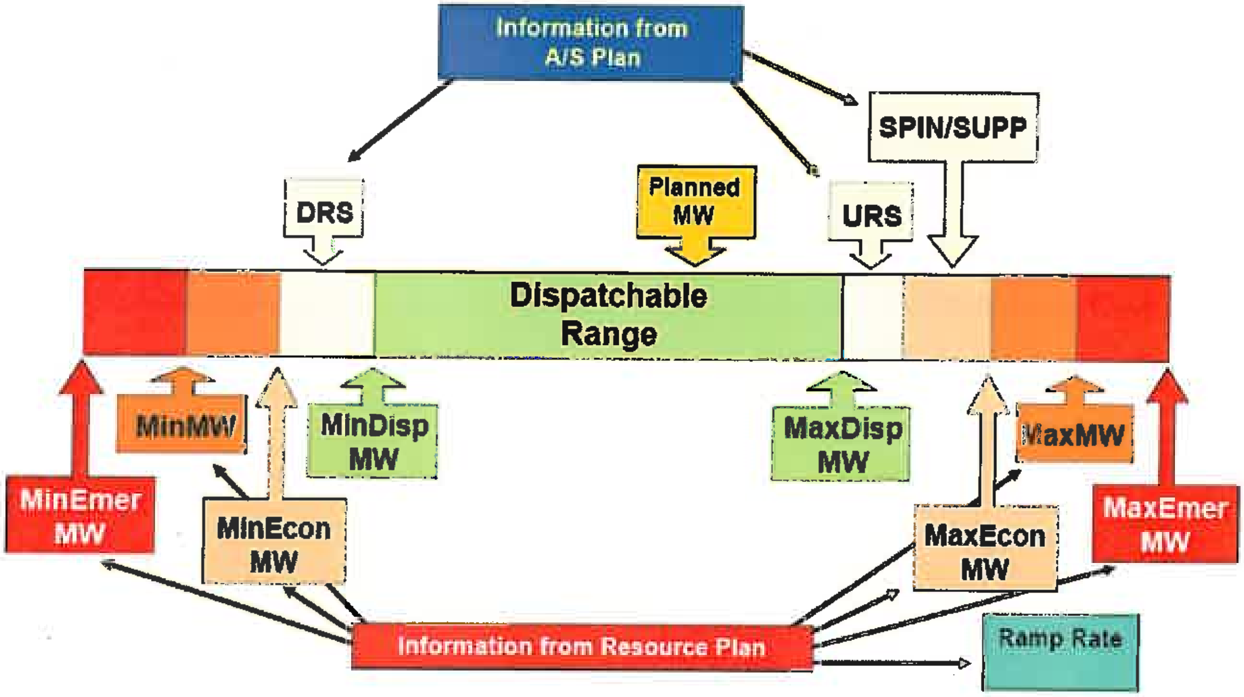
REGUP_o = Regulation Up service being maintained on the Resource as indicated in the Ancillary Service Plan for the Operating Hour (MW).

REGDN_o = Regulation Down service being maintained on the Resource as indicated in the Ancillary Service Plan for the Operating Hour (MW).

RSS_i = Energy scheduled, through the Reserve Sharing System, from the reserves being maintained on the Resources in response to an ARS event for the Dispatch Interval (MW), as defined in Section 6

o = Operating Hour

i = Dispatch interval within Operating Hour.



Dispatch instructions are generated within the range titled *Dispatchable Range*. Operators of Resources use the dispatch instructions to operate their Resources. Dispatch instructions will not deploy below the "Min Dispatchable-MW", nor above the "Max Dispatchable-MW".

The Balancing Authority Area operators regulate the Balancing Authority Area based on the provided NSI.

9.4.1 Provision of Data to the Balancing Authority

Market Operator shall make the following information available to the Balancing Authority/Transmission Operator for each Settlement Area within that Balancing Authority Area:

- Hourly Resource Plan (original and if updated)

- Ancillary Service Plan (original and if updated)
- Hourly Load Forecast
- 5-minute dispatch instruction, excluding price
- Schedules (if any)
- Native Load and Portfolio Schedules (if any)
- Energy Imbalance calculation for each Settlement Area
- Scheduled and Actual Settlement Area Load and/or Generation
- Registration information consisting of unit-to-plant groupings and associated settlement location names as well as information needed to associate WECC's network and SCADA models with the corresponding models maintained by the host Balancing Authority

Market Operator shall make this information available to the Balancing Authority/Transmission Operator immediately after it receives or calculates the above information.

10 Pricing

10.1 Introduction

The Security Constrained Economic Dispatch (SCED) has an objective of minimizing the total cost of energy while honoring the constraints and results in dispatch instructions to deploy EIM Resources. The SCED ~~does not~~ takes into account the differences in marginal loss factors between Resources when calculating dispatch instructions. (Alternatively, if preferred through detailed design discussions for EIM implementation, losses could be excluded from LIPs, and reflected through one of various alternative methodologies.) Deployment of these Resources results in Locational Imbalance Prices (LIP). The LIP for a Settlement Location is the marginal cost ($/MWh) of serving the next increment of demand at that PNode or APNode consistent with existing transmission constraints and the performance characteristics of resources~~integration of the LIPs for the Settlement Location across the 5 minute Deployment Interval~~. LIP is calculated for each Settlement Interval. Settlement Locations may be zonal or nodal for Load, but are only nodal for Resources.

10.2 Content

10.2.1 Locational Imbalance Pricing

Market Operator calculates the price of energy at all Settlement Locations required for the operation of the EIM Market on the basis of Locational Imbalance Pricing in accordance with this Section. The pricing data for each Settlement Location includes:

- Date
- Time
- Settlement Location
- $/MWh

10.2.2 Calculation of Settlement Location Prices for Load

The price used for settlement of Loads is the LIP at the Load's Settlement Location. A Settlement Location price is calculated as the load weighted average of its individual Meter Settlement Location LIPs.

For each Dispatch Interval:

$$LIP_{SLDI} = \frac{SUM[(LIP_{MSL} * MW_{MSLSE})]}{SUM\ (MW_{MSLSE})}$$

For each Settlement Interval (based on hourly meter data requirements for load):

$$LIP_{SL} = SUM\ (LIP_{SLDI})\ /\ \#\ DI\ per\ Settlement\ Interval$$

SL = Settlement Location
MSL = Meter Settlement Location
SE = State Estimator
DI = Deployment Interval

LIP is calculated in real-time using State Estimator data. For locations that report Load for multiple Settlement Locations, the State Estimator will require data to determine the proper allocation of the real time values among the multiple Settlement Locations.

10.2.3 Calculation of Settlement Location Prices for Resources

The price used for settlement of Resources is the LIP at the Resource's Settlement Location. The LIP is the offer price to meet the next MW in a security constrained economic dispatch. The Settlement Location price will be the calculated LIP, weighted by the dispatched MW in each Deployment Interval.

For instructed energy in each Settlement Interval:

$$LIP_{SL} = \frac{SUM[(LIP_{SLDI} * MW_{SLDI})]}{SUM\ (MW_{SLDI})}$$

For uninstructed energy in each Settlement Interval:

$$SUM\ (LIP_{SLDI})\ /\ \#\ DI\ per\ Settlement\ Interval$$

SL = Settlement Location
DI = Deployment Interval

Setting Price

In general, a Resource sets price when its output meets the two following conditions.

1. The Resource is under market dispatch and is deployed.
2. The Resource is not limited in its ability to change output to comply with economic dispatch of EIM energy. Limitations may include the Resource operating at the minimum or maximum of its dispatchable range, ramp rate limitations, other Resource operating limitations, transmission constraints, etc.

A Resource that is not free to change output to move along its offer curve in response to MO's dispatch instructions will not set price.

10.3 Timing and Submission

During the Operating Day, the LIP is calculated and published on OASIS every 5 minutes producing a set of Real-time Prices, 2.5 minutes before the start of the Deployment Interval. The prices produced at deployment intervals are integrated to determine the LIPs for each Settlement Interval, for Settlement Intervals that consist of of multiple Deployment Intervals.. For hourly Settlement Intervals, no ~~No~~ later than fifteen minutes following each Operating Hour, the Market Operator shall post the Locational Imbalance Prices for each Settlement Location and Meter Settlement Location for that Operating Hour on its website and shall indicate in that posting which Meter Settlement Locations were utilized in the calculation of Locational Imbalance Prices for each aggregated load Settlement Location. Since frequent and extensive querying of this data through the MO Portal is likely to adversely impact MO market system operations, MO may curtail, suspend, or otherwise limit a Market Participant's ability to query such data if necessary to prevent such adverse impacts, after an initial warning is provided to the Market Participant regarding its querying practices.

An XML (extensible markup language) file containing this same LIP information shall be posted on the market website www.xxx.org. LIP data shall be posted on an hourly basis during the Operating Day and thereafter shall be consolidated into a daily file, which daily file shall reflect any updated or revised LIP information, and shall indicate the date of revision. LIP information shall remain available on the MO website for three years after the Operating Day. Thereafter, MO shall archive LIP data until the later of seven years from the Operating Day or until there are no disputes pending related to that Operating Day. Market Operator shall make such archived data available to any individual upon request. The data provided in the XML file shall clearly indicate for each nodal LIP the Settlement Location with which it is affiliated. The data provided in the XML file shall also clearly indicate the aggregate LIP for each Settlement Location.

To reduce unnecessary constraints on MO and Market Participant bandwidth and systems all data will be available via a programmatic interface as well as a web page. This programmatic interface will allow users to query for subsets of the LIP data to reduce file size. The programmatic interface will support query by date, time, and location (Settlement Location, PNode, or other nodal value).

Market Operator will make LIPs available for download by Market Participants by Settlement Location, as well as by PNode, through a programmatic settlement interface.

10.4 Use of Data

The integrated LIP for the Settlement Interval is the ~~numerical~~ weighted average of the individual Deployment Interval prices in a Settlement Interval. The MO shall use the resulting settlement prices to settle all imbalance energy in the MO's EIM Market.

11 Settlement and Invoice

11.1 Introduction

This section serves as a resource concerning the Settlement Statements and Invoicing procedures.

Market Operator will produce daily Settlements Statements and weekly Invoices for each Market Participant. The calculations for the charges/credits are based upon meter and schedule data for each Settlement Location for each hour or Deployment Interval, and settled at the Locational Imbalance Price (LIP) for that Settlement Location.

11.2 Settlement Data

11.2.1 Metering Standards for Settlement Data

Metering Standards procedures are specified in the ~~Meter Technical and Data Reporting Protocols, Sections 1 through 4; Appendix D of the Market Protocols~~ Business Practice Manual for Metering.

11.2.2 Settlement Data Reporting Procedures

Settlement Data Reporting processes are specified in the ~~Meter Technical and Data Reporting Protocols, Sections 1-3, 5-6; Appendix D of the Market Protocols~~ Business Practice Manual for Settlements and Billing, sections 2 and 3.

11.2.3 Schedule Data for Settlements

See Scheduling Protocols section 6 of this document.

11.2.4 Public Market Data for Settlement

The Commercial Model, COS Entity Validation (SL to TSIN mapping) shall be available to all market participants for download via the MO ~~portal~~ website and via the Commercial Operations Systems (COS) ~~Programmatic Interface~~. ~~The data will consist of a separate XML file for each MP.~~ Each file will contain the following information:

- Commercial Model shall contain MO's transaction point list with details of transaction point type (i.e. GEN, AGG, LOAD, Controllable Load, etc), start date, and end date. This list will be maintained by MO and ~~communicated~~ updated when transaction points are added, changed, and/or deleted.

- COS Entity Validation (SL to TSIN mapping) shall contain the relationship between Settlement Location, PNode, NERC Source/Sink Name, Start Date, End Date, ~~PSE,~~ and Balancing Authority Area. This list will be maintained by MO and ~~communicated~~ updated when transaction points are added, changed, and/or deleted.

11.2.4.1 Posting of Recalculated LIP

An XML (extensible markup language) file containing the recalculated LIP information shall be posted on the market website www.xxx.org. The data provided in the XML file shall clearly indicate for each nodal LIP the Settlement Location with which it is affiliated. The data provided in the XML file shall also clearly indicate the aggregate LIP for each Settlement Location, and the hour for which the recalculated LIP is effective.

All data will be available via a programmatic interface using XML as well as a web page. This programmatic interface will allow users to query for subsets of the recalculated LIP data to reduce file size. The programmatic interface will support query by date, time, and location (Settlement Location), and for changes across a date range. Notification shall be provided to market participants whenever a recalculated LIP is posted.

11.3 Settlement Statements

Settlement Statements are produced and published for each Operating Day. In order to issue Settlement Statements, MO will use actual, estimated, disputed or calculated meter and schedule data.

A single Operating Day will have both an Initial Statement at T+3B (three business days after the operating day) and ~~Final Settlement~~ Resettlement Statements at T+12B and T+55B, and may contain additional Resettlement Statement for incremental changes in settlement data. Resettlement Statements can be created for any given Operating Day, having met the guidelines for Resettlement.

11.4 Settlement Components

The following sections describe the components that make up the calculation of the Settlement Statements.

11.4.1 Energy Imbalance Service

An energy imbalance settlement is calculated for each settlement interval based on the difference between the Market Participant's Settlement Location Actual Metered and Scheduled Data. Energy Imbalance service does include regulating energy.

11.4.1.1 Calculation of Energy Imbalance Service

All energy deviations between actuals and schedules are settled as Energy Imbalance Service (EIM). Allocation of EIM by Settlement Area is calculated through two steps; 1) Calibration of Load Settlement Location meter data to Net Area Input, and 2) Difference between Calibrated Load Settlement Location Meter Data (CLMD) and Resource Settlement Location meter data for each Market Participant to their respective schedules. The Net Area Input equals the total injections to a Settlement Area, adjusted for net interchange. Load data is a required input for the settlement calculation.

11.4.1.2 Calculation of Market Participant Settlement Quantity

$\text{EIM} = ((\text{Actual Energy}_{SL} + \text{Calibration Energy}_{SL}) - \Sigma\text{Scheduled Energy}_{SL}) * \text{LIP}_{SL}$

Where:

Resources: $\text{Calibration Energy}_{SL} = 0$

Load: $\text{Calibration Energy}_{SL}$ is calculated as shown below.[7]

11.4.1.3 Calculation of Calibration Energy

For each Settlement Area the amount of Calibration Energy represents the difference between the energy input into the Settlement Area and total Load in the Area. This difference is allocated among the Interval Metered (Idata) and Profiled (Pdata) Loads by a ratio calculated through load weighting the Calibration Allocation Factor (CAF) established by the ~~RTO~~ MO for Market Settlement.

The CAF is set to 80%, which results in 80% weighting of Pdata, on a per MWh basis, and 20% weighting of Idata, on a per MWh basis, in allocation of the Settlement Area Calibration Energy. ~~Currently~~ In portions of the MO Market area that do ~~does~~ not include retail choice~~; therefore~~, Pdata will only be used for substitution data. If substituted (Appendix E Section 10.2.3) metering data is used, it will be treated as PDATA.

Per Settlement Area (SA):

Net Area Input = (ΣGeneration Metering + Net Interchange + MO Provided Transmission Losses)

SA Calibration Energy (SACE) = Net Area Input - (ΣPdata + ΣIdata)

Weighted CAF Divisor = (ΣPdata * CAF) + (ΣIdata * (1 – CAF))

"Pdata" CAF = (ΣPdata * CAF)/Weighted CAF Divisor

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[7] This calculation of Calibration Energy is illustrative. The detail on the full calculations, refer to the calculation of unaccounted-for energy in the CAISO's Business Practice Manual for Settlements and Billing.

"Idata" CAF = (∑Idata * CAF)/Weighted CAF Divisor
"Pdata" SA Calibration Factor (PSAFA) = (SACE * "Pdata" CAF)/ ∑ Settlement Area "Pdata"
"Idata" SA Calibration Factor (ISAFA) = (SACE – (PSAFA *∑ Settlement Area "Pdata"))/ ∑ Settlement Area "Idata"

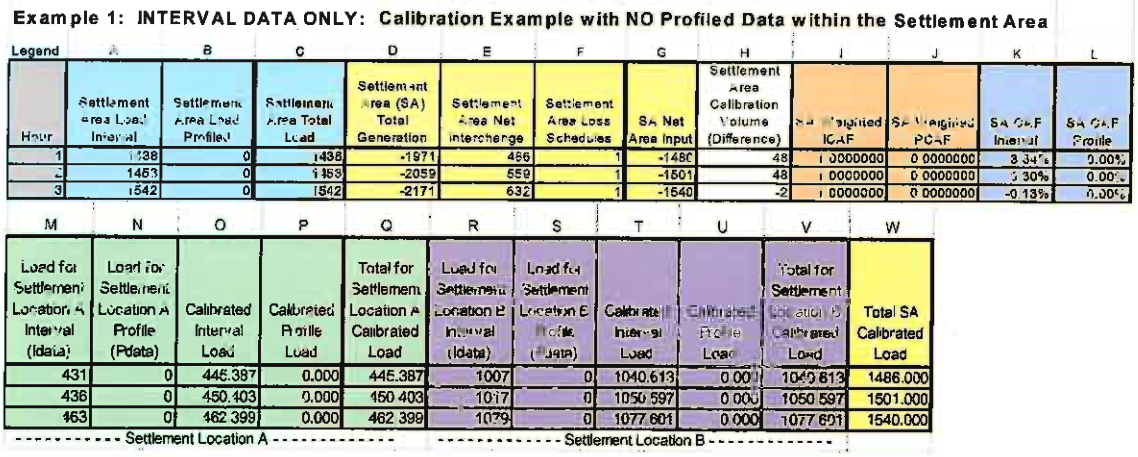
Per Load Serving Entity (LSE) within a Settlement Area:

Calibrated Load Entity "Pdata" (CLE-Pdata) = LSE "Pdata" + (PSAFA * LSE "Pdata")
Calibrated LSE "Idata" (CLE-Idata) = LSE "Idata" + (ISAFA * LSE "Idata")
Calibrated Load Meter Data (CLMD) = CLE-Pdata + CLE-Idata

Calibration Examples:

Legend

Column	Explanation of value calculation
A	Sum of Interval Data for Load SL's reported within the Settlement Area
B	Sum of Profiled Data for Load SL's reported within the Settlement Area
C	B + C = Total Load Settlement Locations within the Settlement Area
D	Sum of Resource SL's reported within the Settlement Area
E	Reported Net Metered Interchange for the Settlement Area
F	SPP Transmission Losses within the Settlement Area
G	D + E - F = SA Net Area Input
H	(G * -1) - C = Difference between SL Load and Settlement Area Load. The amount that will be calibrated to all Load SL's within the SA.
I	Interval Calibration Allocation Factor + I - J Note: Sum of I + J will equal 1.
J	Profiled Calibration Factor = ((80% * B)/((80% * B)+(1-80%)*A)
K	SA CAF for Interval Data = H * I / A
L	SA CAF for Profiled Data = H * J / A
M	Reported Load Settlement Location A Interval Data
N	Reported Load Settlement Location A Profiled Data
O	Interval Settlement Location A Load with calibration included = M + (M * K)
P	Profiled Settlement Location A Load with calibration included = N + (N * L)
Q	Sum of O + P = Total Settlement Location A Calibrated Load
R	Reported Load Settlement Location B Interval Data
S	Reported Load Settlement Location B Profiled Data
T	Interval Settlement Location B Load with calibration included = M + (M * K)
U	Profiled Settlement Location B Load with calibration included = N + (N * L)
V	Sum of O + P = Total Settlement Location B Calibrated Load
W	Sum of Calibration Loads of Settlement Location A and B. This value will equal G: Settlement Area Net Area Input

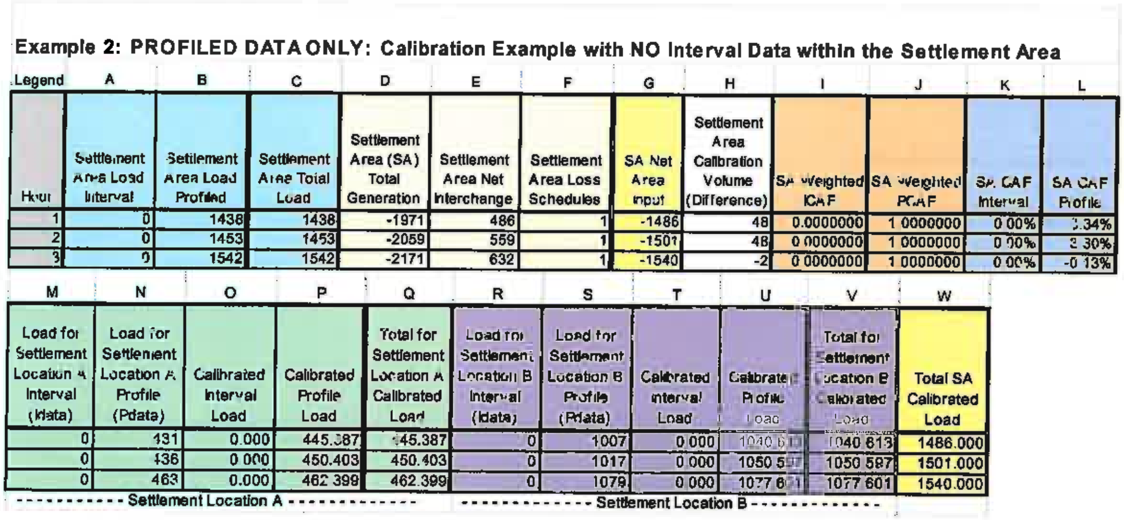


Example 1: INTERVAL DATA ONLY: Calibration Example with NO Profiled Data within the Settlement Area

Legend	A	B	C	D	E	F	G	H	I	J	K	L
Hour	Settlement Area Load Interval	Settlement Area Load Profiled	Settlement Area Total Load	Settlement Area (SA) Total Generation	Settlement Area Net Interchange	Settlement Area Loss Schedules	SA Net Area Input	Settlement Area Calibration Volume (Difference)	SA Weighted ICAF	SA Weighted PCAF	SA CAF Interval	SA CAF Profile
1	1438	0	1438	-1971	466	1	-1480	48	1.0000000	0.0000000	3.34%	0.00%
2	1453	0	1453	-2059	559	1	-1501	48	1.0000000	0.0000000	3.30%	0.00%
3	1542	0	1542	-2171	632	1	-1540	-2	1.0000000	0.0000000	-0.13%	0.00%

M	N	O	P	Q	R	S	T	U	V	W
Load for Settlement Location A Interval (Idata)	Load for Settlement Location A Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location A Calibrated Load	Load for Settlement Location B Interval (Idata)	Load for Settlement Location B Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location B Calibrated Load	Total SA Calibrated Load
431	0	445.387	0.000	445.387	1007	0	1040.613	0.000	1040.613	1486.000
436	0	450.403	0.000	450.403	1017	0	1050.597	0.000	1050.597	1501.000
463	0	462.399	0.000	462.399	1079	0	1077.601	0.000	1077.601	1540.000

------------ Settlement Location A ------------   ------------ Settlement Location B ------------

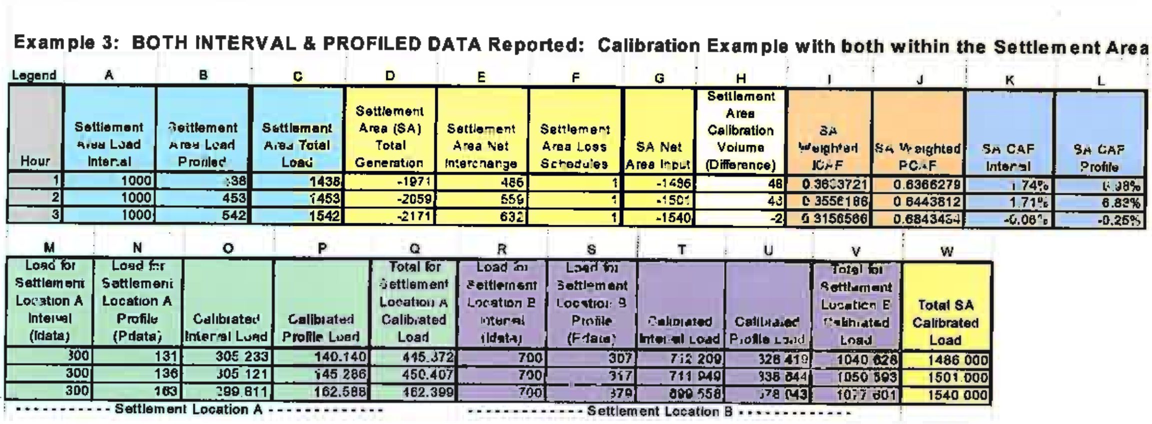


Example 2: PROFILED DATA ONLY: Calibration Example with NO Interval Data within the Settlement Area

Legend	A	B	C	D	E	F	G	H	I	J	K	L
Hour	Settlement Area Load Interval	Settlement Area Load Profiled	Settlement Area Total Load	Settlement Area (SA) Total Generation	Settlement Area Net Interchange	Settlement Area Loss Schedules	SA Net Area Input	Settlement Area Calibration Volume (Difference)	SA Weighted ICAF	SA Weighted PCAF	SA CAF Interval	SA CAF Profile
1	0	1438	1438	-1971	486	1	-1486	48	0.0000000	1.0000000	0.00%	3.34%
2	0	1453	1453	-2059	559	1	-1501	48	0.0000000	1.0000000	0.00%	2.30%
3	0	1542	1542	-2171	632	1	-1540	-2	0.0000000	1.0000000	0.00%	-0.13%

M	N	O	P	Q	R	S	T	U	V	W
Load for Settlement Location A Interval (Idata)	Load for Settlement Location A Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location A Calibrated Load	Load for Settlement Location B Interval (Idata)	Load for Settlement Location B Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location B Calibrated Load	Total SA Calibrated Load
0	431	0.000	445.387	445.387	0	1007	0.000	1040.613	1040.613	1486.000
0	436	0.000	450.403	450.403	0	1017	0.000	1050.587	1050.587	1501.000
0	463	0.000	462.399	462.399	0	1079	0.000	1077.601	1077.601	1540.000

------------ Settlement Location A ------------- ------------- Settlement Location B -------------



Example 3: BOTH INTERVAL & PROFILED DATA Reported: Calibration Example with both within the Settlement Area

Legend	A	B	C	D	E	F	G	H	I	J	K	L
Hour	Settlement Area Load Interval	Settlement Area Load Profiled	Settlement Area Total Load	Settlement Area (SA) Total Generation	Settlement Area Net Interchange	Settlement Area Loss Schedules	SA Net Area Input	Settlement Area Calibration Volume (Difference)	SA Weighted ICAF	SA Weighted PCAF	SA CAF Interval	SA CAF Profile
1	1000	438	1438	-1971	486	1	-1496	48	0.3633721	0.6366279	1.74%	6.98%
2	1000	453	1453	-2059	559	1	-1501	43	0.3556188	0.6443812	1.71%	6.83%
3	1000	542	1542	-2171	632	1	-1540	-2	0.3156566	0.6843434	-0.06%	-0.25%

M	N	O	P	Q	R	S	T	U	V	W
Load for Settlement Location A Interval (Idata)	Load for Settlement Location A Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location A Calibrated Load	Load for Settlement Location B Interval (Idata)	Load for Settlement Location B Profile (Pdata)	Calibrated Interval Load	Calibrated Profile Load	Total for Settlement Location B Calibrated Load	Total SA Calibrated Load
300	131	305.233	140.140	445.372	700	307	712.209	328.419	1040.628	1486.000
300	136	305.121	145.286	450.407	700	317	711.949	338.644	1050.593	1501.000
300	163	299.811	162.588	462.399	700	379	699.558	378.043	1077.601	1540.000

------------ Settlement Location A ------------- ------------- Settlement Location B -------------

11.4.1.4 XML Files for Calibration Billing Determinants

Calibration billing determinant data for each settlement area shall be available to all market participants for download via the portal. The data will consist of a separate daily XML file created for each settlement area. Each settlement area file will contain the following information:

- SA Name
- SA Operating Date
- SA Settlement Type(Initial, Final and Resettlement)
- SA Total Actual Resource Meter Data
- SA Total Substituted Resource Meter Data

- SA Total Resource Data
- SA Total Actual Load Meter Data
- SA Total Profiled Load Meter Data
- SA Total Substituted Load Meter Data
- SA Total Load Meter Data
- SA Interchange Data
- SA Net Area Input
- SA Load Calibration Volume
- SA Actual Interval Calibration Factor
- SA Profile Calibration Factor

11.4.1.5 Calculation of Energy Imbalance Service Charges

For each settlement interval, the EIM charge is based on the EIM energy multiplied by the LIP. A Load that is one megawatt or greater may choose nodal rather than zonal pricing as described in the Pricing Protocols.

11.4.2 Charges for Under-Scheduling and Over-Scheduling

11.4.2.1 Under-Scheduling Charges

During any hour, if Locational Imbalance Prices diverge and a Market Participant's Load imbalance is more than 4% (but at least 2 MW) at an applicable Settlement Location in that hour, that Market Participant may be subject to an Under-Scheduling Charge. If the Reported Load is greater than the Scheduled Load by more than 4% of Reported Load (but at least 2 MW), Under-Scheduling Charges will be determined as follows:

a) For Resource Settlement Locations, the Market Operator shall sort the Market Participant's negative Imbalance Energy amounts in ascending order according to each Resource's Locational Imbalance Price, with a secondary sort in ascending alphanumeric order of the Resource name for any Resources that have the same Locational Imbalance Price.

b) For Load Settlement Locations at which Scheduled Load is less than 96% of Reported Load and the imbalance is at least 2 MW, the Market Operator shall sort the Market Participant's positive Imbalance Energy amounts in ascending order according to each Load's Locational Imbalance Price.

c) Utilizing the sorted lists developed under Sections 11.4.2.1(a) and (b) above, and starting with the Resource with the lowest Locational Imbalance Price, the Market Operator shall match each Resource's Imbalance Energy against that Market Participant's Load Imbalance Energy, starting with the Load Imbalance Energy with the lowest associated Locational Imbalance Price, until all of the Load Imbalance Energy has been accounted for or until no additional Resources remain.

d) The following calculation is performed only for Resources that have a Locational Imbalance Price greater than the Locational Imbalance Price for the associated Load Settlement Location. A Market Participant's Under-Scheduling Charge, for each Resource identified under Section 11.4.2.1(c) as being required to match that Market Participant's Load Imbalance Energy, shall be calculated as follows:

Resource Under-Scheduling Charge = (LLIP – RLIP) * Resource Imbalance Energy,

where

RLIP = Locational Imbalance Price of the Resource Settlement Location,

LLIP = Locational Imbalance Price of the associated Load Settlement Location,

Resource Imbalance Energy = the amount of that Resource's Imbalance Energy required to offset the Market Participant's Load Imbalance Energy as calculated under Section 11.4.2.1(c).

11.4.2.2 Over-Scheduling Charges

During any hour, if Locational Imbalance Prices diverge and a Market Participant's Load imbalance is more than 4% (but at least 2 MW) at an applicable Settlement Location in that hour, that Market Participant may be subject to an Over-Scheduling Charge. If the Scheduled Load is greater than the Reported Load by more than 4% of Reported Load (but at least 2 MW), Over-Scheduling Charges will be determined as follows:

a) For Resource Settlement Locations, the Market Operator shall sort the Market Participant's positive Imbalance Energy amounts in descending order according to each Resource's Locational Imbalance Price, with a secondary sort in ascending alphanumeric order of the Resource name for any Resources that have the same Locational Imbalance Price.

b) For Load Settlement Locations at which Scheduled Load is greater than 104% of Reported Load and the absolute value of the imbalance is at least 2 MW, the Market Operator shall sort the Market Participant's negative Imbalance Energy amounts in descending order according to each Load's Locational Imbalance Price.

c) Utilizing the sorted lists developed under Sections 11.4.2.2(a) and (b), and starting with the Resource with the highest Locational Imbalance Price, the Market Operator shall match each Resource's Imbalance Energy against that Market Participant's Load Imbalance Energy, starting with the Load Imbalance Energy with the highest associated Locational Imbalance Price, until all of the Load Imbalance Energy has been accounted for or until no additional Resources remain.

d) The following calculation is performed only for Resources that have a Locational Imbalance Price less than the Locational Imbalance Price for the associated Load Settlement Location. A Market Participant's Over-Scheduling Charge, for each Resource identified under Section 11.4.2.2(c) as being required to match that Market Participant's Load Imbalance Energy, shall be calculated as follows:

Resource Over-Scheduling Charge = (LLIP-RLIP) * Resource Imbalance Energy,

where

RLIP = Locational Imbalance Price of the Resource Settlement Location,

LLIP = Locational Imbalance Price of the associated Load Settlement Location,

Resource Imbalance Energy = the amount of that Resource's Imbalance Energy required to offset the Market Participant's Load Imbalance Energy as calculated under Section 11.4.2.2(c).

11.4.2.3 Market Monitor Review of Scheduling Practices

The settlement of real-time imbalance energy relative to self-scheduled energy includes uplift charges as well as the settlement of uninstructed energy. These uplift charges are detailed in the Business Practice Manual for Settlements and Billing.

In order to monitor for other price arbitraging, if the Load of a Market Participant is miss-scheduled by more than 4% and the Market Participant's aggregate Resource imbalance is less than their Load miss-schedule while there is congestion, the Market Monitor ~~will~~ may review the data related to the miss-schedule.

In order to determine the frequency and significance of such market situations, the Market Monitor's review can include ~~is to~~ identifying over and under-scheduling relative to the Market Participant's Reported Load when congestion occurs, and ~~to submit monthly~~ reporting its findings to the Federal Energy Regulatory Commission ~~for one year after market start-up~~ on the benefits gained by those Market Participants, the charges made to Market Participants for over or under-scheduling, and any other issue the Market Monitor deems relevant to over and under-scheduling. As a component of this reporting, the Market Monitor ~~is to~~ evaluates, and recommends if needed, changes to the Market Protocols to address any significant issues presented by this ongoing review.

11.4.2.4 Market Monitor Review of Scheduling Relative to Uninstructed Deviation

In addition to Imbalance Energy that results from the difference between schedules and system dispatch, Imbalance Energy can be created when Market Participants deviate from MO deployment instructions. The Market Monitor is to determine if any Resources appear to utilize Uninstructed Deviations in order to profit from price differences resulting from congestion, and to report on the results on a monthly basis.

11.4.2.5 Miscellaneous Adjustment Charge Types

In certain circumstances, it may be necessary to recalculate or make changes to previously billed charges that cannot be handled though a standard final settlement or resettlement execution for that operating day. This is anticipated to occur only on an exception basis.

Market Operator will manually calculate the adjustment and post as a manual adjustment to the appropriate final or resettlement statement for the operating day in question. A miscellaneous charge type will be utilized for each distinct charge type as follows:

- Energy Imbalance Charge Amount - Adjustment
- Uninstructed Deviation Charge Amount - Adjustment
- Over Scheduling Charge Amount - Adjustment
- Under Scheduling Charge Amount - Adjustment
- Revenue Neutrality Uplift Charge Amount - Adjustment
- Miscellaneous Charge Amount

Market Operator will post supporting documentation for manual calculation of any miscellaneous charge to the Portal no later than the time the settlement statement including the miscellaneous charge has been posted.

11.4.3 Revenue Neutrality Uplift Procedure

Market Operator will remain revenue neutral for each hour of the settlement process. When this revenue neutrality is breached and the cause cannot be determined or the benefit/cost of pinpointing causation is not worth the magnitude of the event, MO will apply an Uplift procedure. The uplift and its application will be based on all participants' absolute megawatt-hours in the hourly market in the same time frame where the cause for uplift occurred. That is, all megawatt-hours generated, purchased, and interchanged coincident in the hour(s) in which revenue neutrality was breached will hold a responsibility for that uplift. The calculation of the amount to be uplifted excludes explicit charges and credits related to congestion charges. Uplift will be assigned to appropriate entities as illustrated below:

MO Uplift = Total MO receivables netted against total MO payables for an operating hour

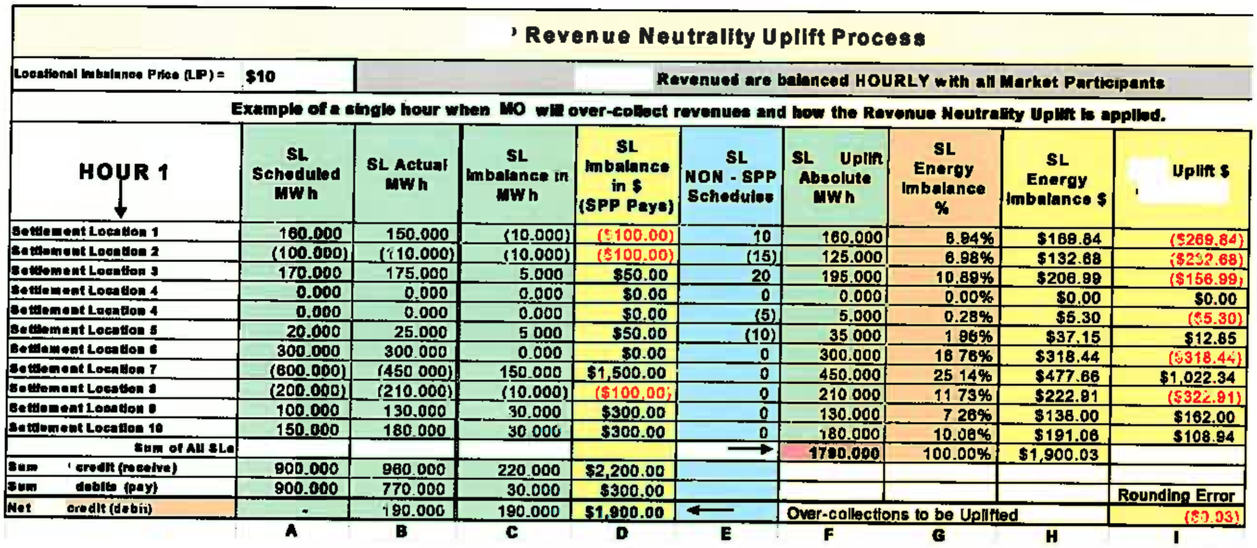
Settlement Location Allocation Factor = ABS (metered actual) +
Σ ABS (schedules to or from outside the market footprint)

Settlement Location Uplift = MO Uplift *
(Settlement Location Allocation Factor / ∑ All Settlement Location Allocation Factors)

Legend:	A	Net Schedules for this Settlement Location. This value from RTO Scheduling System.
	B	Reported Metered Interchange for Settlement Location. This value from Metering Agent(s) Reporting.
	C	B - A = Imbalance for Settlement Location
	D	C * LIP ($10 for this example) = SL Imbalance Charge
	E	Schedules to/from the SL with Non-SWPP Locations. This value from RTO Scheduling System.
	F	Absolute value of B + Absolute value of E
	G	Energy Imbalance Percentage = Column F's (Absolute for the SL / Sum of SL Absolutes)
	H	G * D (Net SPP Revenue Imbalance)
	I	D - H = SL Imbalance $ less SPP SL Uplifted $
	J	Rounding Error is applied to the Largest Absolute (Col I) 100%. This is the final dollars to be transacted for each Settlement Location from this hour.

Examples of MO Revenue Neutrality Uplift Applied:

The assignment of the RNU amount to the appropriate Settlement Location will result in a residual amount settled every hour as a result of rounding inputs at various stages in each calculation. The residual amount is assigned to the Settlement Location with the largest Settlement Location allocation factor for the settlement interval. The amount will be applied to the charge type of Revenue Neutrality Uplift Charge – Adjustment. No other supporting detail is required for use of this type of Adjustment charge.



Revenue Neutrality Uplift Process

Locational Imbalance Price (LIP) = $10 — Revenues are balanced HOURLY with all Market Participants

Example of a single hour when MO will over-collect revenues and how the Revenue Neutrality Uplift is applied.

HOUR 1	SL Scheduled MWh	SL Actual MWh	SL Imbalance in MWh	SL Imbalance in $ (SPP Pays)	SL NON - SPP Schedules	SL Uplift Absolute MWh	SL Energy Imbalance %	SL Energy Imbalance $	Uplift $
Settlement Location 1	160.000	150.000	(10.000)	($100.00)	10	160.000	8.94%	$169.84	($269.84)
Settlement Location 2	(100.000)	(110.000)	(10.000)	($100.00)	(15)	125.000	6.98%	$132.68	($232.68)
Settlement Location 3	170.000	175.000	5.000	$50.00	20	195.000	10.89%	$206.99	($156.99)
Settlement Location 4	0.000	0.000	0.000	$0.00	0	0.000	0.00%	$0.00	$0.00
Settlement Location 4	0.000	0.000	0.000	$0.00	(5)	5.000	0.28%	$5.30	($5.30)
Settlement Location 5	20.000	25.000	5 000	$50.00	(10)	35 000	1 96%	$37.15	$12.85
Settlement Location 6	300.000	300.000	0.000	$0.00	0	300.000	16 76%	$318.44	($318.44)
Settlement Location 7	(600.000)	(450 000)	150.000	$1,500.00	0	450.000	25 14%	$477.66	$1,022.34
Settlement Location 8	(200.000)	(210.000)	(10.000)	($100.00)	0	210 000	11 73%	$222.91	($322.91)
Settlement Location 9	100.000	130.000	30.000	$300.00	0	130.000	7 26%	$138.00	$162.00
Settlement Location 10	150.000	180.000	30 000	$300.00	0	180.000	10.06%	$191.06	$108.94
Sum of All SLs					→	1790.000	100.00%	$1,900.03	
Sum credit (receive)	900.000	960.000	220.000	$2,200.00					
Sum debits (pay)	900.000	770.000	30.000	$300.00					Rounding Error
Net credit (debit)	-	190.000	190.000	$1,900.00	←	Over-collections to be Uplifted			($0.03)
	A	B	C	D	E	F	G	H	I

Market Operator shall post on its website on a monthly basis, by operating hour, the net uplift and the net of each of the following charges types for that hour: (1) all energy imbalance service credits and charges; (2) all uninstructed deviation charges; (3) all over scheduling charges; (4) all under scheduling charges; and (5) by charge type, the net of any other credits or charges not encompassed within (1) through (4). Information for a month shall be posted no later than the 15th day of the succeeding month and shall be posted in a programmatic interface format.

11.5 Settlement Statement Process

11.5.1 Daily Settlement Statement

The settlement statement(s) will be made available for each Operating Day and will be published for statement recipients electronically through the Portal on Business Days. The statement recipient is responsible for accessing the information from the Portal once posted by MO. In order to issue a settlement statement, MO may use estimated, disputed or calculated meter data and schedule information. An Initial and Final Statement will be created for each Operating Day. Resettlement Statements can be created for any given Operating Day having met the dispute-filing deadline and prior to twelve months elapsed time from the Operating Day. When actual validated data and schedule information are available and all of the settlement and billing disputes raised by Statement Recipients during the validation process have been resolved, MO shall recalculate the amounts payable and receivable by the affected Statement Recipient.

For each Market Participant, Settlement Statement(s) will denote:

- Operating Day,
- Statement Recipient's name,
- Market Participant identifier,
- Type of charge (Initial, Final or Resettlement),
- Statement version number,
- Unique Statement identification code, and
- Market services settled.

Settlement Statements will include imbalance charges by the appropriate Settlement Interval and Settlement Location.

11.5.2 Settlement Statement Access

Market Participants can access all Settlement Statements pertaining to them electronically via the following steps:

1. Secured entry on the Portal;
2. eXtensible Markup Language (XML) download.

11.5.3 Settlement Statement Data

Settlement data used to prepare each Settlement Statement will include any available:

a) Actual interval and profiled consumption data for Market Participants by specific node;
b) Actual interval generation data for generation by specific node;
c) Net tie-line metering for each Settlement Area;
d) Resource schedules;
e) Load schedules;
f) Uplift charges.

g) LIP for each Settlement Interval;
h) Adjustments from approved disputes or errors in data components;
i) Tariff billing system inputs not otherwise contemplated above

11.6 Type of Settlement Statements

11.6.1 Initial Settlement Statements

Market Operator will use settlement data to produce the initial statements for each Market Participant for the given Operating Day. Initial statements will be created at the end of the ~~seventh (7th) calendar~~ third (3rd) business day following the Operating Day.~~ If the seventh (7th) day is not a Business Day, the initial statement is issued no later than the next Business Day thereafter.~~

11.6.2 ~~Final Settlement~~ Resettlement Statements

Market Operator will use settlement data to produce the final statements for each Market Participant for the given Operating Day. ~~Final~~ Resettlement statements will be created at the end of the ~~forty-seventh (47th) calendar~~ twelfth (12th) and fifty-fifth (55th) business days following the Operating Day.~~ If the forty-seventh (47th) day is not a Business Day, the final statement is issued on the next Business Day thereafter.~~

The ~~final~~ resettlement statements will reflect changes to settlement charges generated on the Operating Day's initial Settlement Statement.

11.6.3 Additional Resettlement Statements

A resettlement statement will be produced using corrected settlement data due to resolution of disputes, or correction of data errors. Resettlements occurring prior to the production of the ~~final~~ regularly scheduled settlement statement will be included in the ~~final~~ regularly scheduled settlement statement.~~ Resettlement statements 1 through 11 will be created at the end of the following calendar days following the Operating Day. If the calendar day is not a Business Day, the respective resettlement statement is issued on the next Business Day thereafter.~~

~~Resettlement 1 — 77 days after operating day~~
~~Resettlement 2 — 107 days after operating day~~
~~Resettlement 3 — 137 days after operating day~~
~~Resettlement 4 — 167 days after operating day~~
~~Resettlement 5 — 197 days after operating day~~
~~Resettlement 6 — 227 days after operating day~~
~~Resettlement 7 — 257 days after operating day~~
~~Resettlement 8 — 287 days after operating day~~
~~Resettlement 9 — 317 days after operating day~~
~~Resettlement 10 — Ad Hoc~~
~~Resettlement 11 — Ad Hoc~~

~~Resettlement 12 Ad Hoc~~

Resettlement Statements may also publish on T + 9 Months (M), T + 18M, T + 35M and T + 36M. These are optional Settlement Statements and will post only if necessary. Statements published at T + 9M, T + 18M, T + 35M, and T + 36M are categorized as Settlement Statement Reruns in order to exclude FERC Fee charges from the re-settlement. CAISO will publish all optional statements in accordance with the CAISO Payments Calendar and will provide advance notice of publication via a Market Notice.

Unscheduled Resettlement Statements may also publish between T + 9M and T + 18M and between T + 18M and T + 35M in order to correct a CAISO processing error with significant fiscal impact. CAISO will provide 30 days advance notice of the unscheduled publication via a Market Notice. The specific criteria that must be met in order publish an unscheduled statement are:

- The issue has a $1,000,000 per day fiscal market impact for a given Trading Day, and
- The issue is a the result of a CAISO processing error, and
- The issue was identified within the respective settlement dispute window

After the T + 36M sunset, Resettlement Statements may be required for additional Settlement Statement Reruns as directed by the Governing Board or pursuant to a FERC order.

Any settlement and billing dispute of initial statements resolved in accordance with Dispute Resolution process of the Tariff will be corrected on the final statement for the Operating Day. In the event that the final statement does not resolve a dispute from an initial statement for a given Operating Day, MO will resolve the dispute on a Resettlement Statement for that Operating Day. Only Disputes for which the ~~RTO~~ MO is notified by the end of the time period for Dispute Notification will be considered for Resettlement.

~~Any dispute of Initial and Final Statements resolved subsequent to the Final Statement, in accordance with the Dispute Resolution process of the Tariff, will be corrected on the next available invoice after the R2 Resettlement Statement run has been executed.~~

~~Any dispute resolved subsequent to the R2 Resettlement Statement, in accordance with the Dispute Resolution process of the Tariff, will be corrected on the next available invoice after the R4 Resettlement Statement run has been executed.~~

~~Resettlement Statements R1 and R3 will be utilized only if Dispute Resolution for a Granted or Granted with Exception Dispute results in at least a 25% financial change in a Market Participant's Settlement Statement for the operating date as compared with the most recent previous settlement statement for that operating date. Resettlement Statements R5 to R9 will only be used to resolve Disputes of previous Resettlements, which are limited to incremental changes. Resettlement Statements R10 to R12 will be used only on an Ad Hoc basis to resolve any remaining disputes, in accordance with the Dispute Resolution process of the Tariff.~~

~~Notice of Resettlement - MO shall post a Resettlement Schedule through the Portal indicating that a specific Operating Day will be resettled and the date the Resettlement Statement will be issued by MO.~~

11.6.4 Settlement Timeline

Market Operator shall create Settlement Statements daily for each Market Participant, detailing each Market Participants cost responsibility. Settlement Statements are published through the Portal on each business day. Market Operator shall prepare an invoice each billing cycle for each Market Participant showing the net amount to be paid or received by the Market Participant. In order to issue a settlement statement, MO may use estimated, disputed or calculated meter data and schedule information. Settlement Statements shall provide sufficient detail to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Market Operator's settlement systems shall allow Market Participants to search for settlement statements by issuance date, operating date, and invoice date.

~~Settlements Timeline~~

Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday
	Day 1	Day2	Day 3	Day 4	Day 5	Day 6
Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13
	ISS Day 1	ISS Day 2	ISS Day 3	ISS Day 4	ISS Day 5	
Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20
	ISS Day 6 ISS Day 7 ISS Day 8	ISS Day 9	ISS Day 10	ISS Day 11	ISS Day 12	
Time Lapse for Day 21 to Day 48						
Day 49	Day 50	Day 51	Day 52	Day 53	Day 54	Day 55
	ISS Day 41 ISS Day 42 ISS Day 43 FSS Day 3 FSS Day 4 FSS Day 5	ISS Day 44 FSS Day 6	ISS Day 45 FSS Day 7	ISS Day 46 FSS Day 8	ISS Day 47 FSS Day 9	

~~ISS-Initial Settlement Statement~~
~~FSS-Final Settlement Statement~~

~~The following example applies to all Thursday through Sunday holidays and similar logic will apply to other 4 day holiday weekend scenarios:~~

~~Holiday Settlement Timeline Example~~

~~(4-day holiday)~~

~~Sunday~~	~~Monday~~	~~Tuesday~~	~~Wednesday~~	~~Thursday~~	~~Friday~~	~~Saturday~~
~~Nov 14~~	~~Nov 15~~ ~~MD (11/11)~~	~~Nov 16~~ ~~MD (11/12)~~	~~Nov 17~~ ~~MD (11/13)~~	~~Nov 18~~ ~~MD (11/14)~~	~~Nov 19~~ ~~MD (11/15)~~ ~~MD (11/16)~~ ~~MD (11/17)~~	~~Nov 20~~
~~Nov 21~~	~~Nov 22~~ ~~MD (11/18)~~	~~Nov 23~~ ~~MD (11/19)~~ ~~MD (11/20)*~~	~~Nov 24~~ ~~MD (11/21)~~ ~~MD (11/22)~~ ~~ISS (11/17)~~ ~~ISS (11/18)~~ ~~ISS (11/19)~~	~~Nov 25~~ ~~Holiday~~	~~Nov 26~~ ~~Holiday~~	~~Nov 27~~ ~~Holiday~~
~~Nov 28~~ ~~Holiday~~	~~Nov 29~~ ~~MD (11/23)~~ ~~MD (11/24) *~~ ~~ISS (11/20)~~ ~~ISS (11/21)~~	~~Nov 30~~ ~~MD (11/25)~~ ~~MD (11/26)~~ ~~ISS (11/22)~~ ~~ISS (11/23)~~				

~~Meter Data (MD) due by Noon on days indicated.~~
~~* Meter Data due by 3:00pm instead of normal noon deadline.~~
~~Initial Settlement Statement (ISS)~~

11.7 Invoice

Billing is the process where all the charges associated with one or more selected Settlement Runs in a Bill Period are summed to provide totals in "invoice ready" format. This process is executed through a Billing Run and is transparent to Business Associates as there are no outputs provided directly to them as a result of this process.

Outputs from the Billing process are inputs to the Invoicing process, and subsequently to the market clearing system. The "invoice ready" format consists of market participant and MO totals for the Bill Period and is cross-referenced back to the Settlement Runs that are included in that Billing Run.

Market Operator prepares weekly invoices from Settlements Statements. Invoices will be prepared on a net basis, with payments made to or from MO.

Invoices and Payment Advices are published on a weekly basis every Wednesday in accordance with the MO Payments Calendar. To the extent the Wednesday is a MO holiday, the Invoices and Payment Advices are published on the next Business Day following the holiday. Each Invoice or Payment Advice that is published has a unique Invoice number and can contain multiple Bill Periods of varying duration within different Trade Months. ~~Invoices will be posted on the Portal by 8:00 a.m. CPT (see protocol 10.8.2 Holiday Invoice Calendar for exceptions).~~ The Market Participant is responsible for accessing the invoice information via the Portal once posted by MO.

Each Market Participant with a net debit balance will pay any net debit whether or not there is any settlement and billing dispute regarding the amount. Each Market Participant with a net credit balance will receive the balance shown on the Invoice, adjusted for balances not collected from Market Participants with net debit balances.

11.8 Timing and Content of Invoice

Market Operator will electronically post for each Invoice Recipient, an Invoice based on any Initial Statements~~, Final Statements,~~ and Resettlement Statements produced since the prior Settlement Invoice. MO shall post the Settlement Invoices to the Invoice Recipient in accordance with the Settlement Calendar. The Invoice Recipient is responsible for accessing the information from the Portal once posted by MO.

Invoices will be issued on a weekly basis as defined in the Settlement Calendar. Invoice items will be grouped by Initial, Final, and Resettlement categories and will be sorted by Operating Day within each category. Each Settlement Invoice will contain:

a) Customer ID – the name, address and contact information for the customer being invoiced
b) Net Amount Due/Payable – the aggregate summary of all charges owed or due by a Market Participant summarized by Settlement Statement ID and Operating Date and Settlement Date, both being identified by calendar date;
c) Amount Due/Payable by Charge Type, Operating Date and Settlement Date — the aggregate of charges within each charge type owed or due by a Market Participant, listed by Operating Day which shall be identified by calendar date;
d) Time Periods – the time period covered for each settlement statement run date identified by a range of calendar dates;
e) Run Date – the date in which the invoice was created and published;
f) Invoice Reference Number – a unique number generated by the MO applications for payment tracking purposes;
g) Settlement Statement ID– an identification code used to reference each Settlement Statement invoiced;
h) Payment Date and Time – the date and time that invoice amounts are to be paid or received;
i) Remittance Information Details – details including the account number, bank name and electronic transfer instructions of the MO account to which any amounts owed by the

Invoice Recipient are to be paid or of the Invoice Recipient's account to which MO shall draw payments due;

j) Overdue Terms – the terms that would be applied if payments were received late;
k) Late fees; and
l) Miscellaneous charges from tariff billing not otherwise covered above with details provided or referenced on what the miscellaneous charges include and how they are derived.

11.8.1 Invoice Calendar

Weekly invoices will be distributed every Thursday by no later than 8:00 a.m. PPT with the exceptions described in the Holiday Invoice Calendar. Weekly invoices will include the seven daily settlement statements (Initial, Final & Resettlements) produced for the previous Wednesday through Tuesday cycle. Customer balances owed to MO are due by 5:00 p.m. (PPT) of the first Wednesday following the Thursday invoice date. Balances owed by MO to customers will be paid on the second Friday following the invoice date by 5:00 p.m. (PPT).

11.8.2 Holiday Invoice Calendar

The MO invoice calendar will be posted annually on the MO Portal. The Thursday invoice date and the following Wednesday and Friday payment dates as described in Section 10.8.1 will be changed to the next business day if the invoice date or payment date fall on a MO holiday. In those cases when a payment date falls on a bank holiday but not a MO holiday, the payment date will be the next MO business day. If there are two consecutive MO holidays, the following calendar will apply (all invoice dates assume the invoice will be made available to customers by 8:00 a.m. (P~~C~~PT) on the date shown):

Holiday	Invoice Date	Customer Pmt Due Date	MO Pmt Due Date
Mon-Tue	Previous Thu	Fri	Tue
Tue-Wed	Following Mon	Fri	Tue
Wed-Thu	Following Mon	Fri	Tue
Thu-Fri	Following Mon	Fri	Tue
Fri-Mon	Normal Sched	Fri	Tue

11.9 Customer Inquiry, Dispute, and Information Systems

A Market Participant may initiate an inquiry, request information, or dispute items set forth in any settlement statement (Initial, Final, or Resettlement). Each Scheduling Coordinator has an assigned Client Representative as a point of contact.

~~The dispute must be filed on the Portal using the Contents of Notice dispute form. See Attachment AE Section 6.3(a) of OATT for minimum content of a notice of dispute.~~

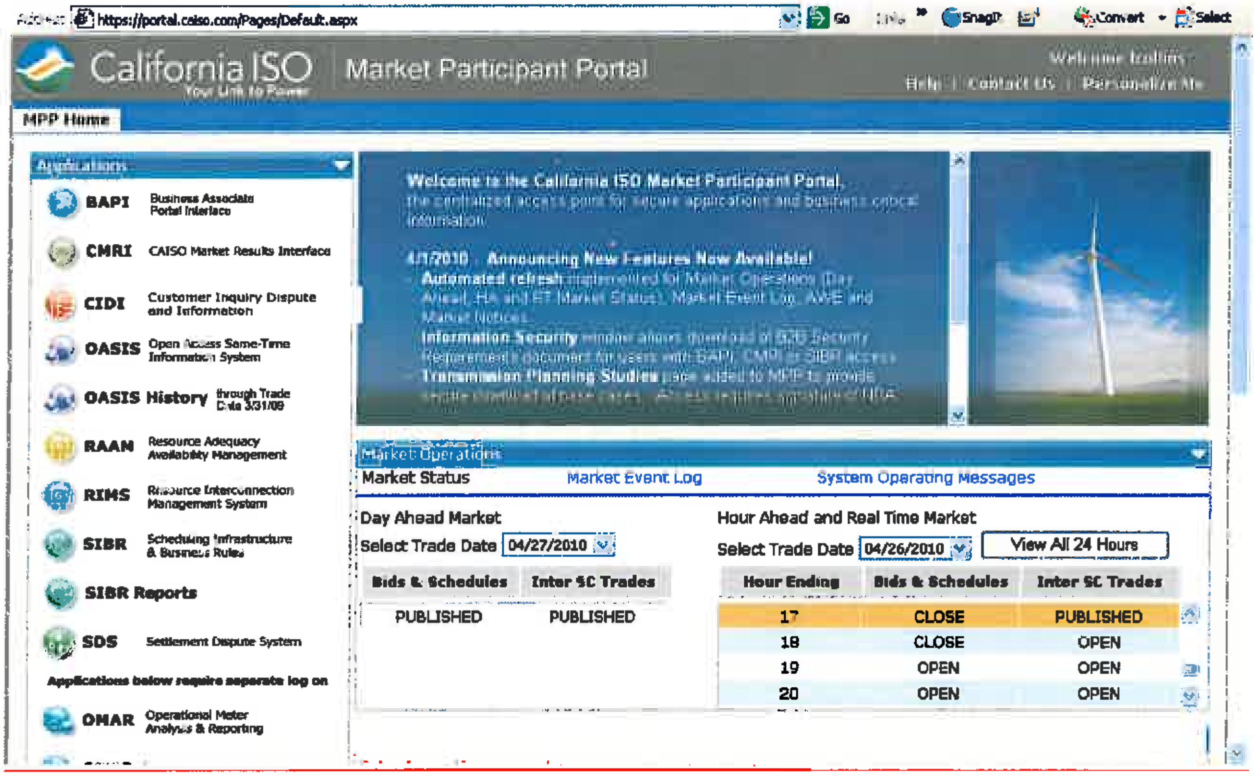
The Customer Inquiry, Dispute & Information system (CIDI, pronounced like 'city') allows market participants to submit and track their business inquiries and disputes. With CIDI, you can:

- Assign your own priority to your inquiries
- Email from the system anyone you choose with information and updates on your tickets (inquiries only for now, but the request has been made to add this feature for settlement disputes)
- Receive automatic reminders including status changes, pending tasks for one of your tickets, or an action item reminder at a future follow-up date you can set.
- Enter longer text descriptions, up to 32,000 characters
- Attach and access files related to your ticket
- Enter text in Case Comments that track with dates the historical interactions, with the ISO (inquiries only)
- Disagree with a resolution, provide comments and automatically re-assign the issue back to the ISO (inquiries only)

The Market Participant Portal (MPP) streamlines access to secure MO applications and business-critical information, enabling more efficient participation with the MO by having:

- Centralized access to ISO applications
- Single log-on to applications using digital certificates
- Centralized access to public information sources of frequent use

MPP has active portlets to issue management, settlements disputes, the MO calendar, market notices, system operating messages, links to legacy applications, and single sign-on links to new applications.



Welcome to the California ISO Market Participant Portal, the centralized access point for secure applications and business critical information.

4/1/2010 Announcing New Features Now Available!

- **Automated refresh** implemented for Market Operations (Day Ahead, HA and RT Market Status), Market Event Log, AWE and Market Notices.
- **Information Security** window allows download of ISO Security Requirements document for users with BAPI, CMRI or SIBR access
- **Transmission Planning Studies** page added to MPP to provide [illegible]

Day Ahead Market

Select Trade Date 04/27/2010

Bids & Schedules	Inter SC Trades
PUBLISHED	PUBLISHED

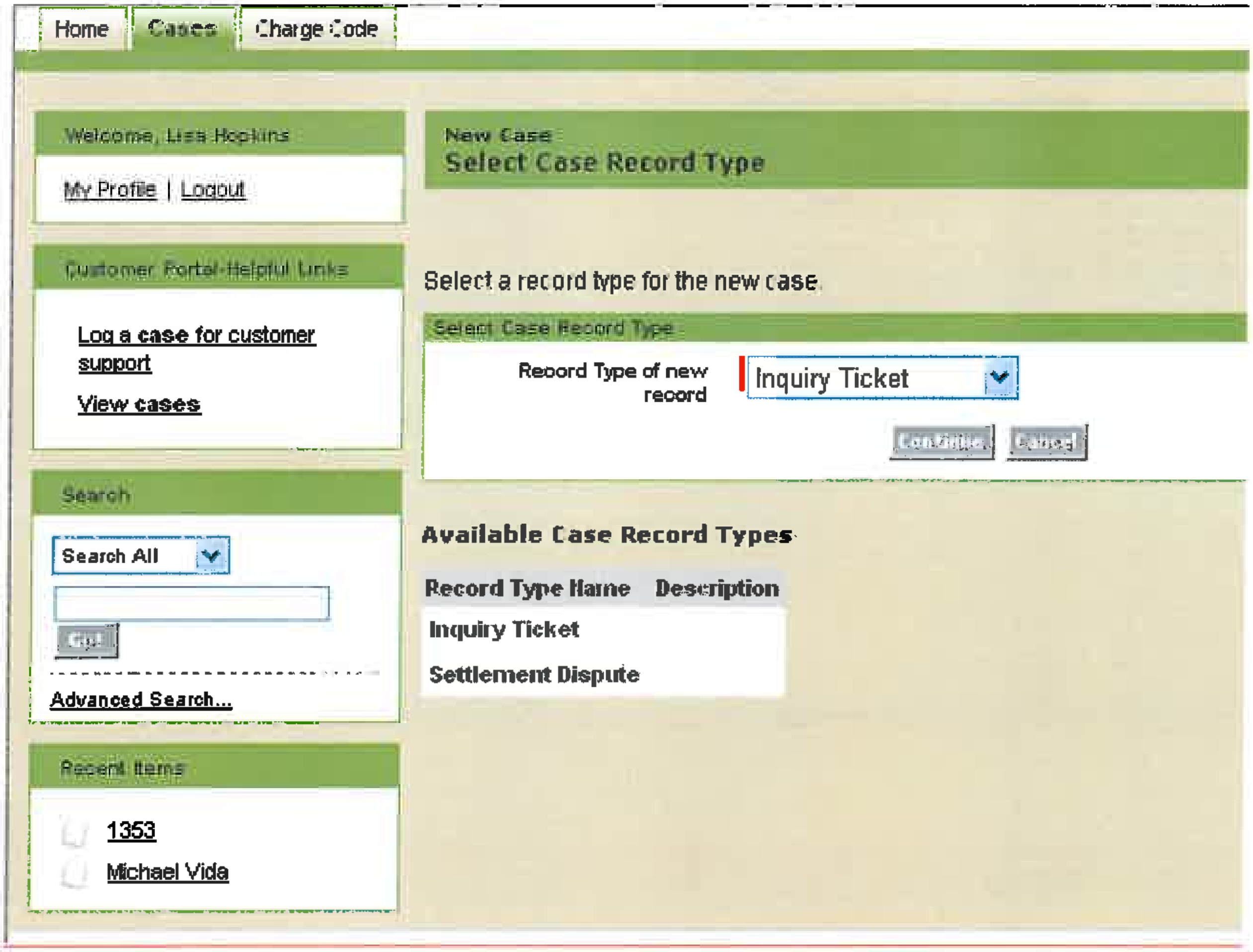
Hour Ahead and Real Time Market

Select Trade Date 04/26/2010

Hour Ending	Bids & Schedules	Inter SC Trades
17	CLOSE	PUBLISHED
18	CLOSE	OPEN
19	OPEN	OPEN
20	OPEN	OPEN

From the Market Participant Portal page, the CIDI application is available through either the CIDI link on the left. The Home page is where you can create a "New Case", view system notices or search for existing cases.

To create an inquiry, enter the CIDI application, click the "Log a case for customer support" link on the Cases tab, and select "Inquiry Ticket" under "New Case, Select Case Record Type".



Select a record type for the new case

Record Type of new record: Inquiry Ticket

Available Case Record Types

Record Type Name	Description
Inquiry Ticket	
Settlement Dispute	

In the Case Edit screen, enter your SCID, subject, inquiry description, category, resource ID, and trade date:

Type IMS

Contact Name Lisa Hopkins

SCID

Subject

Description

Category --None--

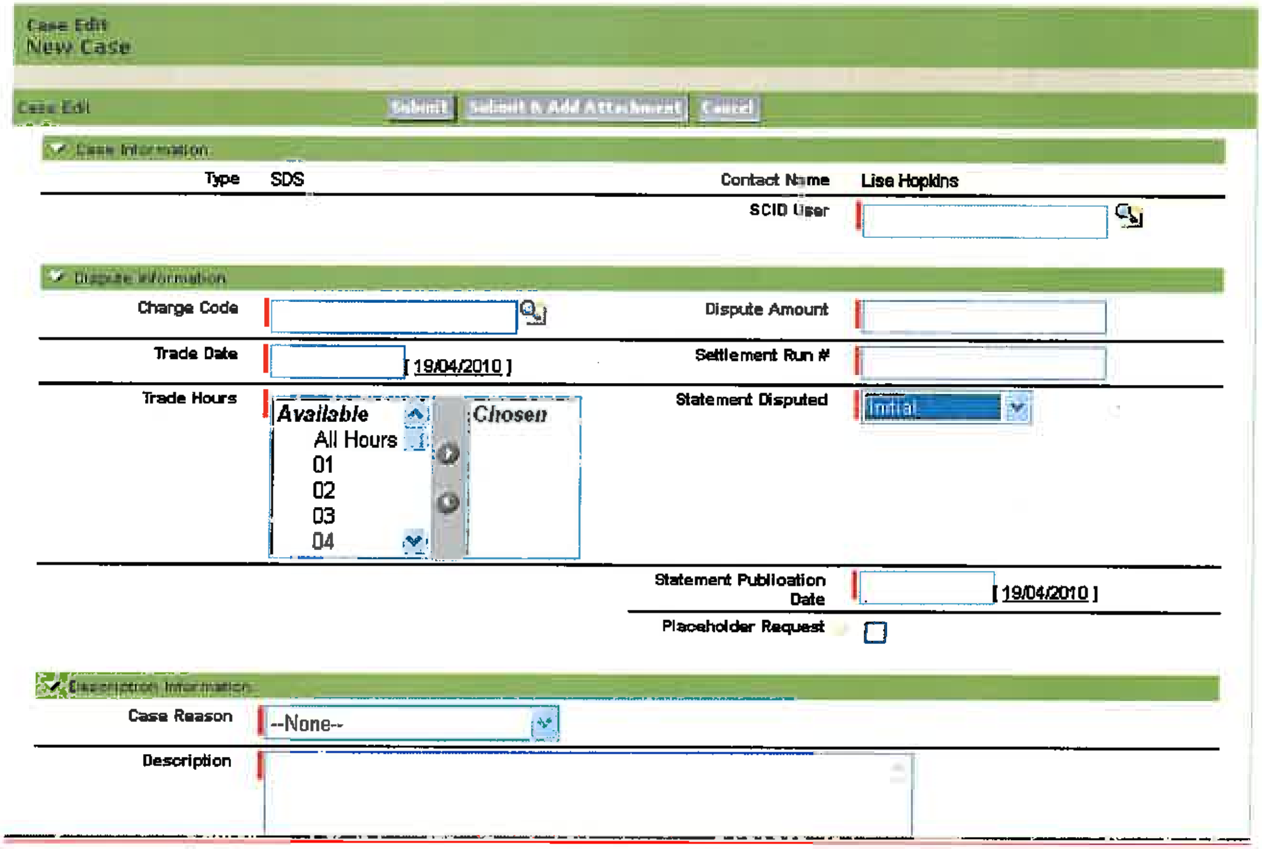
Resource ID

Trade Date [13/04/2010]

Software Reference #

Trade Hours All Hours 01 02 03 04

To create a settlement dispute, enter the CIDI application, click the "Log a case for customer support" link on the Cases tab, and select "Settlement Dispute" under "New Case, Select Case Record Type". Enter all required fields: SCID User, Charge Code, Trade Date, Trade Hours, Dispute Amount, Settlement Run #, Statement Disputed, Statement Publication Date, Case Reason, and Description (up to 32,000 characters).



Type SDS
Contact Name Lisa Hopkins
Statement Disputed Initial
Case Reason --None--

<u>CIDI offers you the ability to print an individual case detail or a view/list of cases, and save the printable version to a folder. CIDI also offers you an ability to clone an existing Inquiry case using the data and information already entered into the system. The Case Detail screen contains all fields specifically used for tracking case information. There are three kinds of client responses to an inquiry case: providing a generic response if a case needs more information to assist MO in finding a response, accepting a resolution or declining a resolution.</u>

<u>Further detail is available in the CIDI User Guide at http://www.caiso.com/Documents/CustomerInquiry_DisputeandInformation_CIDI_UserGuide.pdf.</u>

11.9.1 Dispute Submission Timeline

A Market Participant may dispute settlement of any Operating Day as soon as the Initial Settlement Statement for that Operating Day is issued, and up to 90 calendar days after the Final Settlement Statement for that Operating Day is issued. In the case of Resettlement Statements, a Market Participant may only dispute incremental changes in settlement data that occur between issuance of the Final Settlement Statement and the first Resettlement Statement or between issuance of Resettlement Statements. A dispute relating to a Resettlement Statement must be filed within 14 calendar days of issuance of the Resettlement Statement.

In the event that the Portal is unavailable on the day prior to the deadline for submission of a dispute, due to technical or other reasons, MO shall extend the dispute submittal deadline by the number of Business Days equal to the sequential number of Business Days on which the Portal was unavailable.

11.9.2 Dispute Processing

Market Operator shall determine if the dispute is accepted by verifying that the dispute was submitted within the specified time and contains at least the minimum required information as described in Attachment AE of the OATT. Market Operator shall make reasonable attempts to remedy any informational deficiencies by working with the Market Participant(s).

Contents of Notice will be rejected if MO determines required information is missing. The Dispute will be returned to the Market Participant with an explanation of the missing data no later than thirty days after the receipt of the original or resubmitted dispute. A Market Participant will be able to resubmit the dispute with additional information within 20 Business Days after the Dispute is returned to the Market Participant unless MO grants an extension of this deadline for good cause. Once the Market Participant sends all required information and MO determines the settlement and billing dispute is timely and complete, the dispute status will be considered "Open".

MO will issue a settlement and billing dispute resolution report containing information related to the disposition of the dispute.

MO will make all reasonable attempts to resolve all "Open" disputes relating to all Settlement Statements within 30 calendar days after the settlement and billing dispute due date as specified in the Settlement Calendar. MO will post the necessary adjustments for resolved settlement and billing disputes on the next Resettlement, or Final Settlement process.

For settlement and billing disputes requiring complex research or additional time for resolution, and late disputes that can be reasonably processed, MO will notify the Market Participant of the length of time expected to research and post those disputes through research and, if a portion or all of the dispute is granted, MO will post the necessary adjustments on the next available Settlement Statement for the Operating Day, if any portion or all of the dispute is Granted. Statement or Invoice Recipients have the right to proceed to the External Arbitration process in Dispute Resolution of the Tariff for timely filed disputes that cannot be resolved through the settlement and billing dispute process.

11.9.2.1 Dispute Status

Each dispute will have a status as defined in the following paragraphs. Valid status designation includes:

a) Open,
b) Denied,
c) Closed,
d) Granted, or
e) Granted with Exceptions.

OPEN & CLOSED: A Dispute will be deemed "Open" when submitted in a timely and complete manner. "Closed" is the final status for all Disputes.

DENIED: The Dispute will be "Denied" if MO concludes that the information used in the Dispute is incorrect. MO will notify the Market Participant when a Dispute is "Denied", and will document the supporting research for the denial. If the Market Participant is not satisfied with the outcome of a Denied Settlement and Billing Dispute, the Market Participant may proceed to External Arbitration as described in Dispute Resolution of the Tariff, Dispute Resolution of these Rules. If after 30 calendar days from receiving notice of a "Denied" dispute, the Market Participant does not begin External Arbitration, the dispute will be "Closed".

GRANTED: MO may determine a settlement and billing dispute is "Granted". MO will notify the Market Participant of the resolution, and will document the basis for resolution. Upon resolution of the issue, the settlement and billing dispute will be processed on the next prescribed Settlement Statement for the Operating Day. Once the necessary adjustments appear on the next prescribed Settlement Statement, the settlement and billing dispute is then "Closed".

GRANTED with EXCEPTIONS: MO may determine a settlement and billing dispute is "Granted with Exceptions" when the information is partially correct and MO will provide the exception information to the Market Participant. MO will require an acknowledgement from the Market Participant of the dispute Granted with Exceptions within twenty Business Days. The acknowledgement must indicate acceptance or rejection of the documented exceptions to the dispute. If accepted, MO will post the necessary adjustments on the next prescribed Settlement Statement for the Operating Day and will change the dispute status to "Closed". If MO does not receive a response from the Market Participant within 30 calendar days, the dispute will be considered accepted and "Closed".

If the Market Participant rejects the MO determination of a dispute, which is "Granted with Exceptions", the dispute will be investigated further. After further investigation, if the settlement and billing dispute is subsequently granted, the dispute will be processed on the next prescribed Settlement Statement to be issued. The dispute is then "Closed". If exceptions to the dispute still exist, the Market Participant may either accept the dispute for resolution as "Granted with Exceptions", or begin External Arbitration according to Dispute Resolution of the Tariff, Dispute Resolution of these Rules.

11.10 Invoice Payment Process

11.10.1 Overview of Payment Process

Payments shall be made in a two-step process where:

a) All Settlement Invoices due with net debits owed by Market Participant are paid by 5p.m. (P~~C~~PT) of the first Wednesday following the Thursday invoice date, and
b) All Settlement Invoices due with net credits owed to Market Participant are paid by 5p.m. (P~~C~~PT) of the second Friday following the invoice date

Payments due to MO and payments due to Market Participant will be made by Electronic Funds Transfer (EFT) in U.S. Dollars.

11.10.2 Invoice Payments Due MO

Each Market Participant owing monies to MO shall remit the amount shown on its invoice so MO receives this amount no later than 5 p.m. (P~~C~~PT) on the first Wednesday following the Thursday invoice date. Payments due will be made by Electronic Funds Transfer (EFT) in U.S. Dollars. Payments will be made regardless of any settlement or invoice dispute regarding the amount of the debit. Payments not received by the due date will be subject to interest charges as approved by the Federal Energy Regulatory Commission.

11.10.3 MO Payments to Invoice Recipients

On the first Thursday following the invoice date (or 1 day after payments are due from Market Participants), MO shall calculate (via a payout report) the amounts for distribution to Market Participants with net credits and remit to those Market Participants no later than 5p.m. (P~~C~~PT) the next day. Once each payout report has been finalized, they will be posted to the portal by 3p.m. (P~~C~~PT) on Thursday. At that time, market participants will be able to access information regarding their respective Friday payout amounts. The finalized payout calculations will also be provided to the Customer Relations Department on Thursday afternoon by 3p.m (P~~C~~PT) should Market Participants have any questions regarding the payout amounts posted to the Portal.

11.11 Billing Determinant Anomalies

Circumstances may occur where billing determinants received from system interfaces contain erroneous data anomalies that would have significant adverse financial impacts on market participants if these determinants were used to produce settlement statements. In these situations when certain billing determinants deviate beyond prescribed tolerance levels, MO will substitute the following acceptable values.

11.11.1 Tolerance Levels and Substitution Criteria

SCADA - 5 minute interval value
High Tolerance Band - Greater than 120% of the Resource Plan MaxEmerMW
Substitution value – Dispatch Instructions (results in zero URD)
Low Tolerance Band – Less than Minimum Operating Capacity
Substitution value – Dispatch Instructions (results in zero URD)

Dispatch Instruction - 5 minute interval value
High Tolerance Band - Greater than 120% of the Resource Plan MaxEmerMW
Substitution value – Use SCADA value (results in zero URD)
Low Tolerance Band – Less than Zero
Substitution value – Use SCADA value (results in zero URD)

Resource Meter Data
High Tolerance Band - Trigger value supplied by meter agent/Market Participant
Substitution value – Schedule value
Low Tolerance Band – Auxiliary negative value supplied by meter agent/Market Participant
Substitution value – Schedule value

Load Meter Data
High Tolerance Band - 150% of previous year annual peak
Substitution value – Schedule value
Low Tolerance Band – Zero value
Substitution value – Schedule value

Interchange Meter Data
High Tolerance Band - Trigger value supplied by meter agent/Market Participant
Substitution value – NSI
Low Tolerance Band – Trigger value supplied by meter agent/Market Participant
Substitution value – NSI

12 Registration

12.1 Introduction

All Loads and all Resources excluding Behind the Meter Generation less than 10 MW, must register. Each Market Participant is required to execute the ~~service~~ Scheduling Coordinator agreement specified in Tariff ~~Attachment AH~~ Appendix B-1, and other agreements in Tariff Appendix B as needed for the resources being registered. Registration identifies each Load and/or Resource to Settlement Locations, entity submitting settlement meter data, and settlement responsibilities.

A Market Participant may appoint a Designated Agent to perform its functions under these protocols.

12.2 Content

Market Participants have the legal relationship with MO. The Market Participants may participate in the market as any combination of Resource entities, Load serving entities, Meter Agents, and/or power marketers. The Market Participant is also responsible for insuring that the Balancing Authority also receives Settlement Location Data from the Meter Agent in a suitable electronic format.

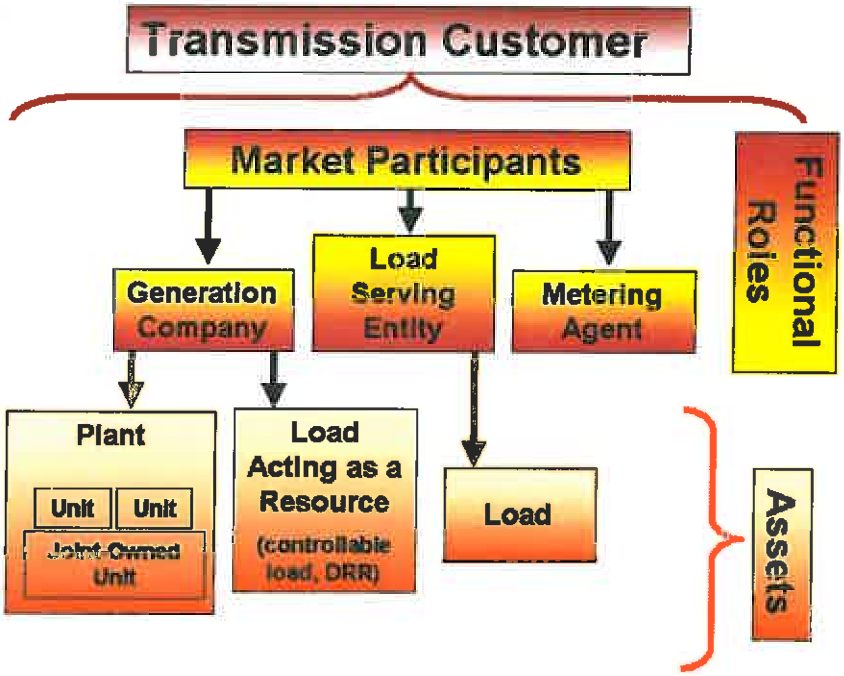
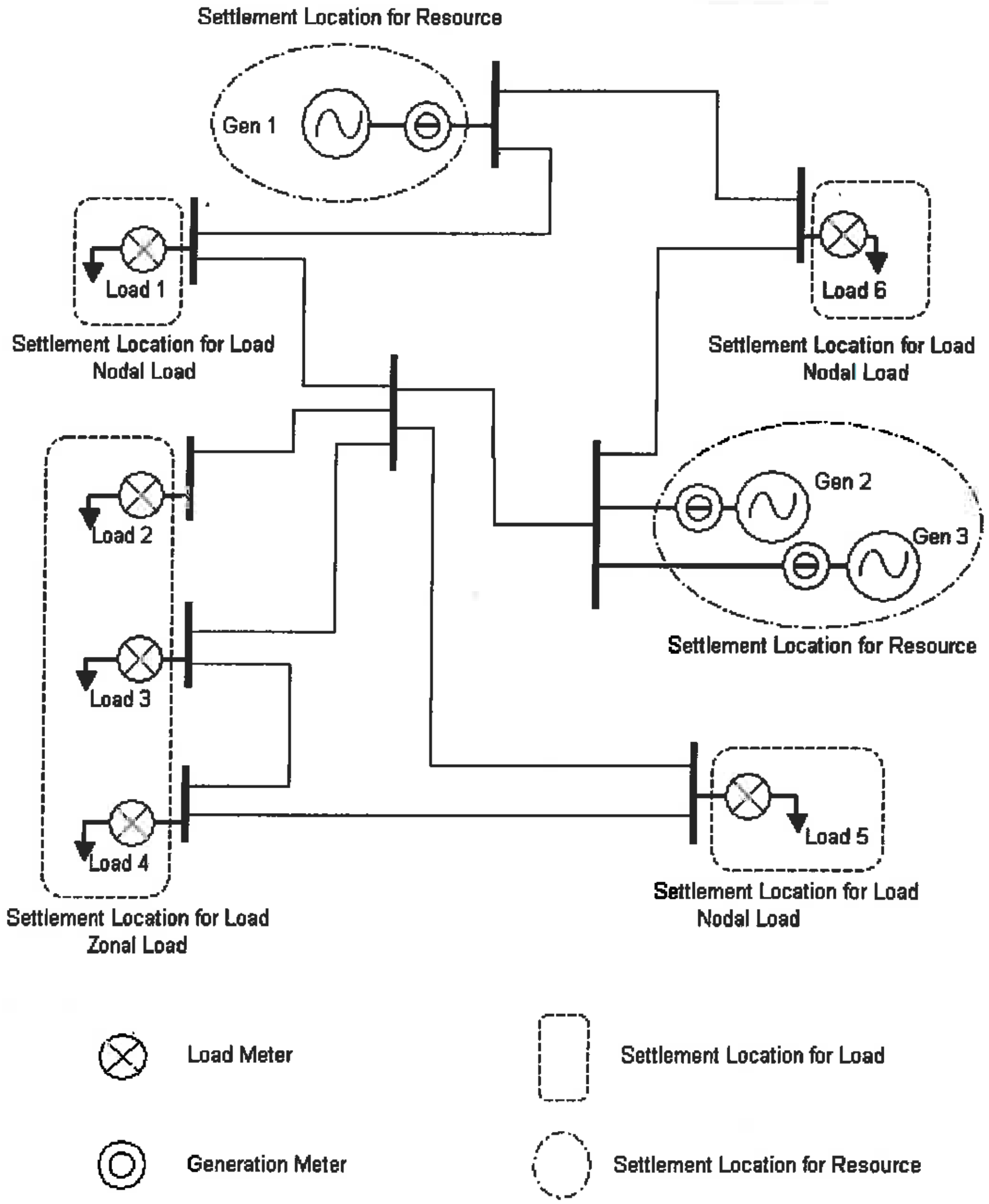


Illustration of Settlement Locations



12.2.1 Registration of Generation Resources and Loads Acting Resources

To register a Resource, an applicant must submit a Registration Package (Appendix A) and be capable of performing the functions of a Resource as described herein. Resources are registered on a nodal basis to Settlement Locations. Resources at the same physical and electrically equivalent injection point to the transmission grid may register at the unit or plant level. Failure or refusal to register a Resource will result in MO filing an unexecuted version of the service agreement(s) as specified in Tariff ~~Attachment AH~~ Appendix B for that Resource with FERC under the name of the generation interconnection customer under an interconnection agreement with MO or the applicable TO.

12.2.1.1 Responsibilities of the Resource

Each MP shall be responsible for conducting its operations in accordance with all applicable MO market rules and guidelines. Each MP shall supply operating characteristics of its Resource, including, but not limited to: Capability, Ramp rate, Location of physical Resource, Legal owner. To the extent that Resources are energy limited and/or intermittent it is the responsibility of the MP to ensure that their Resource Plan reflects the proper availability. Registration shall also include the Settlement Location and Settlement Area of the Resource. The MP is responsible for ensuring that real-time settlement meter data is submitted to MO.

12.2.1.2 Load Acting as a Resource

A MP providing EIM using Load as a Resource must provide a real time signal representing the real power interrupted in response to the deployment of EIM.

12.2.1.3 Energy Production Prior to Completion of Market Registration

Market Participants will be allowed to generate energy prior to the effective date of a submitted market registration packet under the following conditions:

- The MP, or its agent, has submitted a completed registration packet so that the Resource will be registered and recognized in the MO market systems on the next model update.
- If real-time data is not being provided via telemetry to MO Reliability Coordinator (RC) and the host BA, the MP or its agent shall provide to them hourly updates of current output and expected output for each 5-minute interval of the upcoming hour. The actual 5 minute output for the previous hour shall also be provided.
- If the energy production is expected to contribute to any real-time reliability issues on the transmission grid, interruption must occur within 15 minutes upon directive from the MO or RC.
- Appropriate arrangements have been made for delivery of energy.
- Energy shall be limited to a maximum of 10 MW, or a greater amount agreed to by the MO and RC, interconnect TO and any MP with EIM energy that will be affected.
- Energy generated under these provisions will not be recognized as EIM energy in the MO EIM settlement and MO will not be responsible for making any compensation to the generation owner or any Market Participant for the energy produced.

12.2.2 Registration of Load

Any MP with Load within market area must register with MO. To register Load, an applicant must submit a Registration Package (Appendix A) and be capable of performing the functions of Load as described herein. Loads are registered at Settlement Locations within Settlement Areas. Loads may choose to be registered at a Settlement Location consisting of either a single Meter

Settlement Location or multiple Meter Locations. Load aggregation is within a Settlement Area. Load may not be aggregated across Settlement Areas.

12.2.2.1 Responsibilities of the Load

Each MP shall be responsible for conducting its operations in accordance with all applicable market rules and guidelines. The MP is responsible for ensuring that settlement meter data is submitted to MO.

12.2.3 Registration of Meter Agent

All Meter Agents (MA) providing meter data under MO tariff must register with MO (Registration Package – Appendix A). To become registered, MA must be able to demonstrate to MO that it is capable of performing the functions as described herein. Meter data will be provided with the content and format prescribed in these protocols. The Market Participant is also responsible for insuring that the Balancing Authority also receives Settlement Location Data from the Meter Agent in a suitable electronic format.

12.2.4 Registration of a Joint Owned Unit

In the EIM Market there are two options for registering Joint Owned Units (JOU's).

1. Owners of a JOU may agree to register the unit on their own as separate Resource settlement locations.

2. One owner can take responsibility for registering the unit's settlement location.

Additionally, in either case, an owner may choose to have a Designated Agent represent the unit in the market.

Each owner choosing to register the JOU as a separate Resource will be able to submit offers for its share of the unit in to the EIM market, and will be responsible for providing telemetry and meter data to MO for its share of the unit. The registration of an ownership share as a separate Resource results in the JOU being treated as any other Resource, meeting the requirements for Resource Plans, Ancillary Service Plans, Scheduling, and metering.

For jointly owned Resources, the operating owner's Meter Agent shall be the Meter Agent for that jointly owned Resource unless a jointly owned Resource owner designates a different Meter Agent for its share of the Resource.

If only one owner registers the entire unit, that owner will be the only party allowed to submit offers for that Resource, and responsible for all the requirements associated with a Resource, and will be solely financially responsible for EIM charges.

The operating owner must include in its settlement location any ownership by non-market participants (i.e., those not under the Tariff).

12.3 Timing and Submission

General Notes -

1. The "Lead Time" starts when the completed Registration Package and all required technical information is received by SPP and ends when the change is fully implemented in all affected Models, systems, and/or databases such that the change is effective in the Production (PROD) environment. The times in the table below indicate the lead time SPP requires for the complete submission of new registration or updated information.

2. SPP will update the Models on the 1st day of each month for all changes effective that month.

System Update Type (Business Event)	* Lead Time	* Comments
New Market Registration		
Transmission Customer	*45 Days* / 2 months	OASIS Change only if TC not a Market Participant. Access to OASIS is part of Process for Becoming a TC.
Market Participant	6 Months	*A minimum of 6 Months for this addition, which is presumed to inlcude adding all associated assets. (Especially if addition involves changes to Market Boundary.) Include in Applicable scheduled periodic Model Update.*
Designated Agent	45 days / 4 Months	45 days if DA is current SPP TC. 4 months if a new DA that is not currently a SPP TC or MP.
Asset Owner Information		
Generation Company (GENCO)	4 Months	*4 Months for this addition. (This for an addition to a current MP.). Include in Applicable scheduled periodic Model Update.*
Load Serving Entity (LSE)	4 Months	*A minimum of 4 Months for this addition. Include in Applicable scheduled periodic Model Update.*
Metering Agent (MA)	45 days / 4 Months	45 days if MA is current SPP TC. 4 months if a new MA that is not currently a SPP TC or MP.
Asset Information		
Settlement Location	*45 Days* / 4 months	*45 Days* for limited scope additions. 4 Months for Moderate to large scope additions. (This for an addition to a current MP.) (Include in applicable periodic Update)
Plant	*45 Days* / 4 months	*(Same as note above.)*
Unit	*45 Days* / 4 months	*(Same as note above.)*
Load	*45 Days* / 4 months	*(Same as note above.)*
Load Pricing Zones	*45 Days* / 4 months	*(Same as note above.)*
Settlement Area	*4 Months* / 6 Months	4 months if SA is in a current SPP BA. 6 months if a SA is a new BA/CA not previously in SPP.
NERC Source (Via Trans Table)	2 weeks	Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
NERC Sink (Via Trans Table)	2 Weeks	(Same as note above.)
External Generator	*4 Months* / 6 Months	*4 Months* if change involves current MP. 6 Months (minimum) if change involves a new Market Participant.

Market Registration Changes		
Contact Information Changes	2 weeks	Information is updated in COS and forwarded to billing and credit.
Market Footprint Changes		
Move Footprint BA/SA to 1st Tier	6 Months	*Implement in applicable scheduled seasonal/periodic update.*
Move 1st Tier BA/SA to Footprint	6 Months	*Implement in applicable scheduled seasonal/periodic update.*
Acquisition of one BA/SA by another BA/SA	4 Months / 6 Months	4 months if both BAs/SAs are in Market footprint. 6 months if one BA/SA is outside.
Merger of BAs/SAs	4 Months / 6 Months	*(Same as note above.)*
Name Changes		
Transmission Customer (Long Name)	*45 Days*	Name change only - TC must submit new service agreements in new name. (Process should be shortened and improved for this task.)
Transmission Customer (NERC ID)	*45 Days*	*(Same as note above.)*
Market Participant	*4 Months* / 6 Months	*4 Months* for typical scope changes. 6 Months (minimum) if involves changes to Market Boundary and/or changes to all associated assets.
Designated Agent	*45 Days*	45 Days - DA change of responsibility for MP's Assets. (DA is a SPP TC.)
Asset Owner Changes		
Generation Company (GENCO)	4 Months	*Implement in applicable periodic update.*
Load Serving Entity (LSE)	4 Months	*Implement in applicable periodic update.*
Metering Agent (MA)	4 Months	*Implement in applicable periodic update.*
Asset Information Changes		
Settlement Location	*45 Days* / 4 months	*45 Days* for limited scope changes. 4 Months for Moderate to large scope changes.
Plant	*45 Days* / 4 months	*(Same as note above.)*
Unit	*45 Days* / 4 months	*(Same as note above.)*
Load	*45 Days* / 4 months	*(Same as note above.)*
Load Pricing Zones	*45 Days* / 4 months	*(Same as note above.)*

Settlement Area	4 Months / 6 Months	4 Months for limited scope changes. 6 Months for Moderate to large scope changes. (Typically a Settlement Area will not change unless the NERC ID changes or there is a major Control Area consolidation event.)
External Generator Changes	*45 Days* / 4 months	*45 Days* for limited scope changes. 4 Months for Moderate to large scope changes. (Involves existing MP.)
Commercial Model Relationship Changes		
Market Participant / Transmission Customer	*45 Days* / 4 months	45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Typically this change would occur when an MP to TC change occurs.)
Asset / Market Participant (GENCO / LSE)	*45 Days* / 4 months	45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Typically this change would occur when an MP to TC change occurs.)
Settlement Location / Settlement Area	*45 Days* / 4 months	45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Very rare change, this should only occur if a Settlement Area change takes place.)
Settlement Location / Metering Agent	*45 Days* / 4 months	45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Must register Meter Agent if relationship change is not to existing Meter Agent.)
Settlement Area / Metering Agent	*45 Days* / 4 months	*(Same as note above.)*
NERC Source/Sink / Settlement Location	On the fly - 1 week at most. Due to scheduling, MP needs to be notified when active.	These changes must occur "as needed" COS; TSIN Registry updates are downloaded daily and need to be incorporated into WebData as soon as possible. NERC to Siebel runs nightly. Siebel to Webdata only runs weekly.
De-aggregating a Plant to Individual Units	*45 Days*	*Implement in applicable periodic update.*
Aggregating Individual Units to a Plant	*45 Days*	*Implement in applicable periodic update.*
Breaking out an Individual Unit from a Plant	*45 Days*	*Implement in applicable periodic update.*
IDC Mapping Changes	45 Days	Changes are incorporated during periodic Model Updates. IDC data updated on monthly and Semi-annual bases -- Monthly changes accumulate for the month and are implemented one day per month (includes time to re-map units to Market Systems). Semi-annual changes accumulate over six months and are implemented over four days twice a year. (June 1st and October 1st are the update times)
NERC Source/Sink Mapping Changes	2 weeks	Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
DNR Designation Changes	2 weeks	(Same as note above.)
Certification Changes	*45 Days*	*Implement in applicable periodic update.*
Resource Reasonable Limit MW Value Changes	1 Week	This change will impact EMS, MOS, RSS, and NLS information (RTO_SS). (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
Load Pricing Zone Changes	*45 Days*	*Implement in applicable periodic update.*
Individual Loads to Load Aggregate Changes	*45 Days* / 4 months	*45 Days* for intra-CA/SA changes. 4 Months for Changes involving 2 or more CAs/SAs

Market Termination Request		
Transmission Customer	1 Week (Minimum) / 4 Months	1 week for OASIS Change only if TC not a Market Participant. 4 Months if TC is MP (TC may have outstanding requests, can not terminate until end of contract.)
Market Participant	4 months	*Implement in applicable periodic update.*
Designated Agent	*45 Days*	45 Days - DA change of responsibility for MP's Assets. (DA is a SPP TC.)
Asset Owner		
Generation Company (GENCO)	4 months	*Implement in applicable periodic update.*
Load Serving Entity (LSE)	4 months	*Implement in applicable periodic update.*
Metering Agent (MA)	4 months	*Implement in applicable periodic update.*
Asset Information		
Settlement Location	*45 Days* / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in applicable periodic Update)*
Plant	*45 Days* / 4 months	*(Same as note above.)*
Unit	*45 Days* / 4 months	*(Same as note above.)*
Load Pricing Zone	*45 Days* / 4 months	*(Same as note above.)*
Settlement Area	4 months	*Implement in applicable periodic update.*
1st Tier CA/External Aggregate	*45 Days* / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in applicable periodic Update)*
NERC Source (via Translation Table)	2 Weeks	Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
NERC Sink (via Translation Table)	2 Weeks	(Same as note above.)

Add EMS NETMOM/GENMOM/SCADAMOM Equipment		
In Market Footprint		
Control Area/EMS Company	4 months / 6 Months	*4 Months for limited scope changes. 6 Months for Moderate to large scope changes. This change will also impact COS, MOS, and other models. (Include in applicable periodic Update)*
Units	*45 Days* / 4 months	*(Same as note above.)*
Loads	*45 Days* / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	*45 Days* / 4 months	*(Same as note above.)*
In 1st Tier Entity		
Control Area/EMS Company	4 months / 6 Months	*4 Months for limited scope changes. 6 Months for Moderate to large scope changes. This change will also impact COS, MOS, and other models. (Include in applicable periodic Update)*
Loads	*45 Days* / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	*45 Days* / 4 months	*(Same as note above.)*
Beyond 1st Tier	*45 Days* / 4 months	*(Same as note above.)*

Modify EMS NETMOM/GENMOM/SCADAMOM Equipment		
Changes - In Market Footprint		
Control Area/EMS Company	45 Days / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)*
Units	45 Days / 4 months	*(Same as note above.)*
Loads	45 Days / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	45 Days / 4 months	*(Same as note above.)*
In 1st Tier Entity		
Control Area/EMS Company	45 Days / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)*
Loads	45 Days / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	45 Days / 4 months	*(Same as note above.)*
All Other Changes	45 Days / 4 months	*(Same as note above.)*

Remove EMS NETMOM/GENMOM/SCADAMOM Equipment		
In Market Footprint		
Control Area/EMS Company	45 Days / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)*
Units	45 Days / 4 months	*(Same as note above.)*
Loads	45 Days / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	45 Days / 4 months	*(Same as note above.)*
In 1st Tier Entity		
Control Area/EMS Company	45 Days / 4 months	*45 Days for limited scope changes. 4 Months for Moderate to large scope changes. (Include in periodic Update)*
Loads	45 Days / 4 months	*(Same as note above.)*
Other Equipment ND, LD, LN, CAP, XFMR, ZBR, DCLN, CB, DSC, LS	45 Days / 4 months	*(Same as note above.)*
Beyond 1st Tier	45 Days / 4 months	*(Same as note above.)*
Add EMS Contingency		
In Market Footprint	2 weeks	Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
In 1st Tier Entity	2 weeks	(Same as note above.)
Beyond 1st Tier	2 weeks	(Same as note above.)

Remove EMS Contingency		
In Market Footprint	2 weeks	Include in scheduled and coordinated rolling type updates. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)
In 1st Tier Entity	2 weeks	(Same as note above.)
Beyond 1st Tier	2 weeks	(Same as note above.)
Add New Flowgate		
In SPP Region		
AFC	*45 Days*	*Implement in applicable periodic update.*
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Temporary	On the fly.	Implement this type change as needed.
In Other Regions		
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Modify Flowgate Data		
Changes - In SPP Region		
AFC	*45 Days*	*Implement in applicable periodic update.*
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Temporary	On the fly.	Implement this type change as needed.
Changes - In Other Regions		
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Remove Flowgate		
In SPP Region		
AFC	*45 Days*	*Implement in applicable periodic update.*
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Temporary	On the fly.	(Planned Function)
In Other Regions		
Coordinated	*45 Days*	*Implement in applicable periodic update.*
Reciprocal	*45 Days*	*Implement in applicable periodic update.*
Define New ICCP Inbound		
In Market Footprint	1 Week / 4 Months	1 Week for basic ICCP/Scada Ref. additions. 4 Months for Generation and load related changes
In Reliability Area	1 Week / 4 Months	(Same as note above.)
PNODE	1 Week / 4 Months	(Same as note above.)
EMS Equipment or Station Name	1 Week / 4 Months	(Same as note above.)
IDC Bus or Machine ID	1 Week / 4 Months	(Same as note above.)

Change ICCP Inbound		
In Market Footprint	4 Months	4 Months for Generation and load related changes.
In Reliability Area	4 Months	(Same as note above.)
PNODE	4 Months	(Same as note above.)
EMS Equipment or Station Name	4 Months	(Same as note above.)
IDC Bus or Machine ID	4 Months	(Same as note above.)
Delete ICCP Inbound points		
(Typical for any type ICCP Deletion)	1 Week / 5 Weeks	The max time for deletions is five weeks unless there is no impact to any other system (local or remote). If there is no impact, the request can be completed in the next ICCP model update.
Define New ICCP Outbound points		
In Market Footprint	4 Months	4 Months for Generation and load related changes.
In Reliability Area	4 Months	(Same as note above.)
PNODE	4 Months	(Same as note above.)
EMS Equipment or Station Name	4 Months	(Same as note above.)
IDC Bus or Machine ID	4 Months	(Same as note above.)
Change ICCP Outbound points		
In Market Footprint	4 Months	4 Months for Generation and load related changes.
In Reliability Area	4 Months	(Same as note above.)
PNODE	4 Months	(Same as note above.)
EMS Equipment or Station Name	4 Months	(Same as note above.)
IDC Bus or Machine ID	4 Months	(Same as note above.)
Delete ICCP Outbound points		
(Typical for any type ICCP Deletion)	1 Week / 5 Weeks	The max time for deletions is five weeks unless there is no impact to any other system (local or remote). If there is no impact, the request can be completed in the next ICCP model update.
Add PLC Points		
In Market Footprint		
Plant	4 Months	*Implement in applicable periodic update.*
Unit	4 Months	*Implement in applicable periodic update.*
Other	4 Months	*Implement in applicable periodic update.*
In Reliability Area		
Plant	4 Months	*Implement in applicable periodic update.*
Unit	4 Months	*Implement in applicable periodic update.*
Other	4 Months	*Implement in applicable periodic update.*
Change PLC Points		
In Market Footprint		
Plant	4 Months	*Implement in applicable periodic update.*
Unit	4 Months	*Implement in applicable periodic update.*
Other	4 Months	*Implement in applicable periodic update.*
In Reliability Area		
Plant	4 Months	*Implement in applicable periodic update.*
Unit	4 Months	*Implement in applicable periodic update.*
Other	4 Months	*Implement in applicable periodic update.*

IDC Model Change		
IDC Bus Name or Machine ID Change	45 Days	Changes are incorporated during periodic Model Updates. IDC data updated on monthly and Semi-annual bases -- Monthly changes accumulate for the month and are implemented one day per month (includes time to re-map units to Market Systems). Semi-annual changes accumulate over six months and are implemented over four days twice a year. (June 1st and October 1st are the update times)
RSS		
Add New Resources	1 Week	*Change to RSS Model only. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)*
Change Resource Information	1 Week	*(Same as note above.)*
Delete Resource Information	1 Week	*(Same as note above.)*
NLS		
Add New Resources	1 Week	*Change to NLS Model only. (This type change may need to be implemented prior to the next scheduled periodic Model Update.)*
Change Resource Information	1 Week	*(Same as note above.)*
Delete Resource Information	1 Week	*(Same as note above.)*

12.4 Model Update Timeline

The Full Network Model Database Release Schedule is published on the MO web site, currently available at http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx. Network model updates generally take place bi-monthly, and include projects with an estimated operational date before or on a designated date after the subsequent model release, based on operational dates listed in the Resource Interconnection Management System (RIMS) database. ~~The following table is the Model Update Timeline.~~ Market Registration related model changes that do not require updates to the Full Network Model are managed in the MO's master file, and take place ~~Bi-Monthly~~ more frequently (e.g., with a week's notice).

~~Production Model Upload date~~	~~Reliability-related model changes~~	~~Market Registration related model changes~~
~~January 1st~~	~~X~~	-
~~February 1st~~	~~X~~	~~X~~
~~March 1st~~	~~X~~	-
~~April 1st~~	~~X~~	~~X~~
~~May 1st~~	~~X~~	-
~~June 1st~~	~~X~~	~~X~~
~~July 1st~~	~~X~~	-

~~August 1st~~	~~X~~	~~X~~
~~September 1st~~	~~X~~	~~-~~
~~October 1st~~	~~X~~	~~X~~
~~November 1st~~	~~X~~	~~-~~
~~December 1st~~	~~X~~	~~X~~

12.5 Use of Data

Registration data is used for operation and settlement of the EIM market, identifying responsibilities and identifying discrete entities. The registration data is also used in the interaction of Customer Relations personnel with MP's.

13 Outage Handling and Error Handling

13.1 Real Time System Outages

Outages in the real-time market systems can result in an inability to communicate deployment instructions to participants as well as a potential loss of real-time pricing data used in settlements. The following principles guide the policies for how to handle real-time system outages:

1. Maintain reliability of the transmission system.
2. Financial settlement continues.
3. Pricing will provide incentive for scheduling of Load and Resources to minimize imbalance.

In the event of a system outage or loss of critical system data, MO will notify WECC and affected participants. MO may direct affected participants to no longer participate in imbalance energy deployments, or to take other actions to prevent a market disruption or to minimize the extent of a market disruption. Upon receiving such notification, participants should bring their affected Resources to scheduled levels over the next 30 minutes, except to the extent such Resources are used to provide regulation service, unless otherwise directed by MO. The affected host Balancing Authority Areas will also be notified.

In the event that a failure of MO's real-time market systems results in a loss of pricing information, imbalance energy will continue to be settled financially under the Tariff. ~~For each transmission zone with missing data, each supplier of Regulation Service (under any OATT) for that zone shall provide its Incremental Cost of providing such service within 24 hours of MO's making request for such information. For each zone, the highest cost of energy produced or procured for the supply of regulation service used in that zone will be substituted for missing price data in that zone.~~

Details of MO's response to market disruptions, and of the settlements for the duration of the market disruption, are contained in section 7.7.15 of the MO tariff.

~~The following table details the appropriate actions that should be taken for several scenarios:~~

~~13.2 MO Market Outage Scenarios~~

	~~Actions~~	
~~Scenario~~	~~Real-time (Market/Reliability)~~	~~Settlements~~
~~1. Real-time market system (MOS) is performing, with a loss of state estimator data~~		
~~a. Partial lost of state estimator because of SCADA.~~		
~~1. few buses (*e.g.*, a single RTU communication circuit fails)~~	~~The state estimator will continue to solve. MO will have displays and procedures whereby the operators will observe MW mismatch at adjacent buses. As long as the mismatch is minimal, the presumption will be that the market can continue operating on the data.~~ ~~If MO is not receiving telemetry then the operator may override the status of the unit to indicate it is no longer under MO control ("self dispatch").~~	~~None.~~
~~2. an entire member's data~~	~~In all but extreme cases, MO's state estimator will continue to solve. Operators can make assumptions about what's going on in the Balancing Authority Area based on the mismatch of the other side~~	~~None.~~

	~~Actions~~	
~~**Scenario**~~	~~Real-time (Market/Reliability)~~	~~Settlements~~
	~~of tieline measurements of the other company, but cannot observe Load changes what individual units in the company are doing.~~ ~~MO should notify the affected participants that their units should run at scheduled levels except to the extent that those units are providing regulation service.~~ ~~MO will work with the effected area to provide their NSI and energy imbalance component. The member can add the energy imbalance deployment to their ?? Scheduling System NSI. As a consequence, other market participants will continue to provide EIM service to the effected area.~~	
~~2. MOS is performing, but the state estimator and/or SCADA has entirely failed~~		
~~a. Less than 30 minutes~~	~~The market system will continue to run with the last available state estimator save case. That would mean that Load and system topology would remain constant in the system. It is expected that this would not substantially impact the~~	~~None.~~

	~~Actions~~	
~~Scenario~~	~~Real-time (Market/Reliability)~~	~~Settlements~~
	~~solution for a period of time.~~	
~~b. 30 minutes or more (or sooner if reliability conditions warrant)~~	~~Suspend imbalance deployment and notify all participants that they must take necessary steps to either self-provide imbalance or make a third party, bilateral arrangement.~~ ~~Market Deployment should be ramped out over a period, of time, ideally at least 30 minutes.~~ ~~Market Participants are expected to minimize Imbalance during this period. Any remaining imbalance will be tracked after the fact and settled financially.~~	~~Settlement data will continue to be available. Pricing information that would otherwise come from MOS will be determined by the production or procurement cost by suppliers of Regulation Service for each Zone in accordance with the applicable provisions of the Tariff.~~ ~~MO will post to the OASIS the applicable time periods. Since this is not a repricing condition, a FERC filing is not required.~~
~~3. MOS has failed~~		
~~a. Up to twelve consecutive 5-minute Deployment Intervals~~	~~Market deployments and the associated energy imbalance portion of NSI will be frozen while schedule NSI may continue to change. Participants will control generation in such a manner as to minimize Balancing Authority Area ACE.~~	~~Settlement data will continue to be available. Pricing information that would otherwise come from MOS would be duplicated from the last known good interval for up to one hour.~~
~~b. Over 12 consecutive 5-minute Deployment Intervals(or sooner if reliability conditions warrant)~~	~~Suspend imbalance deployment and notify all participants that they must take necessary steps to either self-provide imbalance or make a third party, bilateral arrangement.~~	~~Settlement data will continue to be available. Pricing information that would otherwise come from MOS will be determined by the production or procurement~~

	~~**Actions**~~	
~~**Scenario**~~	~~Real-time (Market/Reliability)~~	~~Settlements~~
	~~Market Deployment should be ramped out over a period, ideally over at least 30 minutes.~~ ~~Market Participants are expected to minimize Imbalance during this period. Any remaining imbalance will be tracked after-the-fact and settled financially.~~	~~cost by suppliers of Regulation Service for each Zone in accordance with the applicable provisions of the Tariff.~~ ~~MO will post to the OASIS the applicable time periods. Since this is not a repricing condition, a FERC filing is not required.~~

~~13.3~~13.2 Procedures for Correcting LIPs Resulting From Market Software and Data Input Errors

The MO Staff, with the assistance of the MMU as appropriate, shall monitor for possible Market Software and Data Input Errors by MO in the EIM Market. If Market Software and Data Input Errors are identified, MO shall impose corrective measures as specified below and take immediate action to remedy such errors as soon as possible.

Market Software and Data Input Errors are a flaw in the design or implementation of software and the data inputs for that software that result in LIPs that do not accurately reflect the application of the Tariff.

Events that may result in Market Software and Data Input Errors include, but are not limited to:

- Bad or missing SCADA
- Load Forecast Error
- Missing Schedules
- Missing Intervals
- Operator/Human Error
- RSS Events

The occurrence of any of these events may warrant a revision to LIPs and are flagged by MO Operations. MO Operations will investigate all such events and determine if a LIP revision is necessary.

~~13.3.1~~13.2.1 Procedure for Evaluating and Correcting Market Software and Data Input Errors

~~In any instance in which MO makes price corrections, it shall, as soon as possible thereafter, correct the Market Software and Data Input Errors that resulted in incorrect prices. MO shall undertake this work in consultation and cooperation with Market Participants and jurisdictional agencies, as appropriate and as time permits.~~
The MO monitors the market clearing software solutions for all market intervals to determine whether prices are calculated accurately, consistent with the provisions of the MO tariff. To the extent reasonably practicable, the MO shall correct erroneous prices identified through such monitoring and re-run the relevant markets prior to publication of prices on its Open Access Same-Time Information System (OASIS) or provision of prices directly to market participants, if applicable. All prices for each trading day shall become subject to the MO's price correction process once the MO publishes them on its OASIS or provides them directly to market participants, if applicable. For all prices, the price correction process for each trading day shall end no later than the end of the fifth calendar day following that trading day. The MO will not make price corrections after this price correction process time period has expired, except as otherwise directed by the Federal Energy Regulatory Commission. Further details of the price correction process are stated in section 35 of the MO tariff.

~~13.3.2~~13.2.2 Procedures for Revising LIPs in Response to Market Software and Data Input Errors

~~13.3.2.1~~13.2.2.1 Circumstances When MO Shall Revise LIPs

MO shall revise LIPs when they deviate from what would be produced absent an identified Market Software and Data Input Error.

~~13.3.2.2~~13.2.2.2 Notice to Market Participants and the Public

In any hour for which MO reasonably believes that a Market Software and Data Input Error will require correction of one or more LIPs, MO shall post on its OASIS and website as soon as reasonably practicable a notice that it is considering a correction for that hour. When MO is aware in advance that a price correction will be required for an hour, MO will post a notice of a proposed correction, and if possible a description of the proposed action, before bids are to be submitted for such hour. If the circumstances do not permit advance notice, MO shall post a notice no later than 5:00 p.m. on the calendar day following the day in which the hour occurs for which LIPs would be affected by the contemplated price correction.

Prior to making a price correction, if reasonably possible, MO must post on its OASIS and website a description of its proposed price correction. In any event, MO must post a description of the proposed price correction within five (5) calendar days after the date on which a notice of a price correction is posted. If a description of the proposed price correction is not posted within such period, the notice of proposed price correction shall be deemed to be withdrawn as to that hour. If MO determines that a price correction is not necessary, it shall withdraw the notice of possible price correction from its OASIS and website as soon as reasonably practicable.

~~13.3.2.3~~13.2.2.3 Price Corrections Identified After the End of the Notice Period

If MO identifies a Market Software and Data Input Error requiring a price correction, but does not (a) post a notice of price correction or (b) post a description of the proposed price correction within the required time periods, MO shall request a tariff waiver from FERC to perform the necessary price correction. MO shall utilize the following process for requesting such tariff waiver:

1. First, MO shall review with the appropriate MO organizational group the need for the price correction and the schedule for fixing the Market Software and Data Input Error causing the need for price correction:
2. Second, MO shall seek approval of the MO Board of Directors for filing a price correction tariff waiver request at FERC. Prior to seeking the Board's approval, MO shall submit its request proposal to the appropriate MO organizational group ~~MO Market Working Group and the MO Markets and Operations Policy Committee~~ for approval; and
3. Third, after approval by the MO Board of Directors, MO shall file the price correction tariff waiver request at FERC as soon as reasonably practicable.

   This process ensures that MO stakeholders are consulted prior to the implementation of any price correction that does not occur within the allotted time frame for such corrections.

~~13.3.2.4~~13.2.2.4 Process for Recalculating Prices

MO shall recalculate LIPs in a manner that reflects, as closely as reasonably practicable, the LIPs that would have resulted but for the Market Software and Data Input Error, and shall substitute the recalculated LIPs for the prices that resulted from the Market Software and Data Input Error. Such recalculated LIPs shall serve as the basis for Settlement. Such recalculated LIPs shall be provided to Market Participants in the same manner as LIPs determined in the ordinary course of business (i.e. in a programmatically downloadable file).

~~13.3.2.5~~13.2.2.5 Compensatory Payments to Market Participants for a Decrease in LIP

If recalculated LIPs would result in a Market Participant being paid less than its offered price for the actual output of a Resource as dispatched due to the Market Software and Data Input Error, MO will make a compensatory payment to the Market Participant to make up the difference between the recalculated LIP and the offered price. Such compensatory payment shall be uplifted to the EIM Market during settlement to ensure revenue neutrality for MO. The following examples illustrate calculation of compensatory payments. Additional details are provided in section 11.21 of the MO tariff.

Example 1: Price Adjusted Downward – Spot Energy Sale

Resource Offer = 100 MW @ $60/MWh
Schedule = 0 MW

Initial Settlement

Original LIP = $80
Actual Dispatch = 100 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $80 * (0 MW – 100 MW)
= -$8,000 {~~RTO~~ MO pays the Market Participant}

Recalculated LIP

Recalculated LIP = $30
Actual Dispatch = 100 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $30 * (0 MW – 100 MW)
= -$3,000 {~~RTO~~ MO pays the Market Participant}

Additional Compensation for Incorrect LIP

Error Compensation = Actual Unscheduled Production * (Recalculated LIP - Offer)
= 100 MW * ($30 - $60)
= -$3,000 {~~RTO~~ MO pays the Market Participant}

Total Settlement

Total Settlement = Recalculated LIP settlement + Error Compensation
= -$3,000 - $3,000

= -$6,000 {~~RTO~~ MO pays the Market Participant}

End Result:

The final cost to the Market Participant is their cost of production ($6,000)

Example 2: Price Adjusted Downward – Scheduled and Offered Resource

Resource Offer = 100 MW @ $60/MWh
Schedule = 100 MW

Initial Settlement

Original LIP = $80
Actual Dispatch = 100 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $80 * (100 MW – 100 MW)
= $0

Recalculated LIP

Recalculated LIP = $30
Actual Dispatch = 100 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $30 * (100 MW – 100 MW)
= $0

Additional Compensation for Incorrect LIP

Error Compensation = Actual Unscheduled Production * (Recalculated LIP - Offer)
= 0 MW * ($30 - $60)
= $0

Total Settlement

Total Settlement = Recalculated LIP settlement + Error Compensation
= $0 + $0
= $0

End Result:

The final cost to the Market Participant is their cost of production ($6,000). However, note that if the initial LIP had been correct, the Resource would not have been dispatched, and the Market Participants cost would have been $3,000 (100MW * $30/Mwh). There will be no compensation for this lost opportunity.

~~13.3.2.6~~13.2.2.6 Make-Whole Payments to Market Participants for an Increase in LIP

If recalculated LIPs result in a Market Participant being charged more for imbalance energy purchased as a direct result of the Market Participant's Resources having been dispatched incorrectly due to a Market Software and Data Input Error, MO will make a make-whole payment to that Market Participant in an amount that reflects the difference between the recalculated LIP and the Market Participant's offer from the Resource and the difference between the Adjusted Dispatch and the Actual Dispatch.

Example: Price Adjusted Upward – Scheduled and Offered Resource

Resource Offer = 150 MW @ $60/MWh
Schedule = 100 MW

Initial Settlement

Original LIP = $30
Actual Dispatch = 0 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $30 * (100 MW – 0 MW)
= $3,000 {Market Participant pays the ~~RTO~~ MO}

Recalculated LIP

Recalculated LIP = $80
Actual Dispatch = 0 MW

Settlement = LIP * (Scheduled Gen – Actual Gen)
= $80 * (100 MW – 0 MW)
= $8,000 {Market Participant pays the ~~RTO~~ MO}

If the LIP had been calculated correctly, the Market Participant's Resource would have been dispatched. The Market Participant's cost would have been its cost of production (100 MW * $60 = $6,000). As PRR 30 currently stands, no compensation is provided for the ~~RTO's~~ MO's error. The Market Participant owes $8,000.

PROPOSED Additional Compensation for Incorrect LIP

Adjusted Dispatch = lesser of Recalculated Dispatch or Scheduled injection
= Recalculated Dispatch of 150 MW, Schedule of 100 MW
= 100 MW

Error Compensation = (Adjusted Dispatch – Actual Dispatch) * (Offer – Recalc. LIP)
= (100 MW – 0 MW) * ($60 - $80)
= -$2,000 {~~RTO~~ MO pays the Market Participant}

Total Settlement

Total Settlement = Recalculated LIP settlement + Error Compensation
= $8,000 - $2,000
= $6,000 {Market Participant pays the ~~RTO~~ MO}

End Result:

The final cost to the Market Participant is what their cost of production would have been had the Market Software and Data Input Error not been made.

~~13.3.3~~13.2.3 Disputes and Resettlement Provisions

If a stakeholder does not agree with a price correction made by MO within the allotted time frame for such correction, the stakeholder may use the dispute and resettlement mechanism provided in Section 10 of these Market Protocols to resolve such disagreement.

~~13.4~~13.3 Procedures for Handling Incorrect Schedule Adjustments Resulting from Market Software and Data Input Errors

Due to software or data input errors, the CAT or UFMP may incorrectly adjusts schedules in real-time by either adjusting or failing to adjust schedules properly for the given system conditions. MO will notify the appropriate stakeholder group of the incorrect operation, the financial impact to revenue neutrality and the steps taken to mitigate this event in the future.

In the event the CAT or UFMP failed to curtail schedules in real-time, MO will not make any after the fact schedule adjustments.

In the event the CAT or UFMP curtailed a schedule in real-time beyond what was appropriate for the given system conditions, MO will notify and coordinate with the affected MPs to determine the appropriate after-the-fact schedule reinstatement. Due to actions that may have been taken by MPs in response to the adjustment, the MP(s) affected by the incorrect curtailment(s) may, but are not required, to agree to after-the-fact-schedule reinstatement. In the case of NERC tagged schedules, the affected parties to the NERC tag must agree on any after the fact reinstatements. After-the-fact reinstatements will not be allowed if MO and the affected MP(s) do not reach an agreement or if the associated NERC tags cannot also be revised. After-the-fact schedule reinstatements will only be allowed if such changes would not have resulted in changes in dispatch or prices.

14 Market Monitoring and Mitigation

14.1 Introduction

Market monitoring and mitigation is intended to provide for the monitoring by the MO Market Monitor of MO's Markets and Services and mitigation by the Transmission Provider of the potential exercise of horizontal and vertical market power by Market Participants. Market monitoring and mitigation are essential functions for Regional Transmission Organizations (RTOs) and are required by FERC's Order 2000.

14.2 Purpose and Objective

A. Objective

The objective of the Market Monitoring function is to (a) protect consumers against abuse of horizontal and vertical market power in MO's Markets and Services by any Market Participant and (b) ensure that the design and implementation of MO's Markets and Services is as efficient as possible, so that consumers may obtain the best deal based on price, risk and reliability. The Market Monitor will work to ensure that their functions and activities are implemented fairly and consistently, and that they protect and foster competition while minimizing interference with open and competitive markets. Correcting market inefficiencies and preventing the exercise of market power in advance rather than punishing offenders afterward shall be the preferred approach to ensure that consumers obtain the best deal.

The Market Monitor will evaluate existing and proposed market rules, tariff provisions, and market design elements and recommend proposed rules and tariff changes to the Transmission Provider, the Commission's Office of Energy Market Regulation (or its successor organization) staff, and other interested entities such as state commissions and Market Participants. The Market Monitor will limit distribution of its identifications and recommendations to the Transmission Provider and the Commission's Office of Energy Market Regulations (or its successor organization) staff in the event that the Market Monitor believes that broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided.

The Market Monitor will review the performance of the wholesale market and provide an annual report on the state of the market as provided in ~~Section 7 of Attachment AE of~~ the OATT.

B. Independence of the Market Monitor

The Market Monitor shall be granted complete independence to perform those activities necessary to provide impartial and effective market monitoring within the scope of the Protocols. No person or entity may screen, alter, delete or delay the findings, conclusions and recommendations developed by the Market Monitor that fall within the scope of the market monitoring responsibilities contained in the Tariff and these Protocols.

C. Resolution of Conflicts

In the event there is a conflict between this Section 14 of the Market Protocols and Attachment ~~AG~~ XX of the Tariff or any other provision of the Tariff, Attachment ~~AG~~ XX will control.

D. Maintenance of Monitoring Protocols

The Market Monitor is responsible for reviewing and recommending updates to these market monitoring protocols at least every three years and supporting MO in obtaining approval from FERC for any such updates with input and support from the MWG and MO staff.

14.3 Market Monitoring

14.3.1 Market Monitor

A. Staffing and Resources

The Market Monitoring function for MO will be staffed by internal employees. FERC in an order, 109 FERC ¶ 61, 009 in October 2004 granting RTO status to MO states that:

> "In addition, we note that Order No. 2000's market monitoring requirements may be satisfied with various market monitoring unit structures. If MO determines that another structure to meeting its market monitoring obligations is appropriate, such as through an internal market monitoring unit, MO may propose such a market monitoring unit consistent with what the Commission has approved for other RTOs."

The MO internal Market Monitoring Unit (MMU) is responsible for all functions and shall be an organization within MO reporting to the Board of Directors, excluding any MO management representatives serving on the Board of Directors.

B. Relationships and Notifications

As a general principle, the Market Monitor may obtain input from the MWG, FERC Staff, MO Staff, the RSC, and affected state regulatory authorities for the purpose of executing its duties. The Market Monitor shall bring any instances of market behavior that may require investigation (including, but not limited to, suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch) to the attention of the Board, the officers of MO, FERC's Office of Enforcement (or its successor organization) staff, and affected state regulatory authorities, as the Market Monitor may deem necessary or appropriate. After any initial inquiry, the Market Monitor shall also provide notification to the Board of Directors, the President of MO, and FERC's Office of Enforcement (or its successor organization) staff, and other interested entities such as relevant state regulatory commissions and Market Participants, as soon as practicable in the event it identifies a significant market problem that may require (a) further review, (b) a change in MO's tariffs or market rules, or (c) referral to FERC. In the event the Market Monitor believes broader dissemination could lead to exploitation, it may limit distribution of its identifications and recommendations to the Board of Directors, the President of MO, and FERC Staff with an explanation of why further dissemination should be avoided at that time.

The MMU shall also interface with FERC Staff and other RTO and ISO market monitors in adjacent regions as needed for the purpose of addressing electricity market issues in a comprehensive manner. The Market Monitor shall report to the MO Board of Directors.

C. Standards of Conduct

The MMU shall abide by MO's Standards of Conduct, which shall be appropriate for establishing the professional and financial independence of the MMU. The MMU shall certify compliance with such policies to the Board. Consistent with Order No. 719 requirements for MMU ethics standards, the Market Monitor and its employees shall comply with those standards outlined in ~~Section 3.3 of~~ Attachment ~~AG~~ XX of the MO OATT.

14.3.2 Market Monitoring

The primary purposes of market monitoring are to (a) obtain objective information about MO's Markets and Services, (b) assess the behavior of Market Participants, and (c) assess the behavior of other markets and services that impact the performance of MO's Markets and Services. Key aspects of such market monitoring are (a) assessing the design and structure of MO's Markets and Services to ensure market efficiency, (b) determining Market Participants' compliance with market rules and (c) preventing the exercise of horizontal and/or vertical market power, which includes whether a Market Participant is affecting MO's ability to provide reliable and non-discriminatory service.

A. Markets to be Monitored

The Market Monitor will monitor MO's Markets and Services, which are the markets that are operated by, and the services provided by, MO under its OATT. The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by MO, except to assess the effect of these markets and services on MO's Markets and Services, or the effects of MO's Markets and Services on these unmonitored markets. Similarly, the Market Monitor will not monitor the energy, transmission or capacity markets and services in regions adjacent to MO except to assess the effect of these markets and services on MO's Markets and Services, or the effects of MO's Markets and Services on these adjacent markets.

• Monitoring Activities

The Market Monitor will implement the market monitoring protocols and will monitor Markets and Services by reviewing and analyzing market data and information including, but not limited to:

a) Resource and Ancillary Services (Capacity) Plans, schedules and Offer Curves submitted for Resources in or affecting any of Markets and Services;
b) Actual commitment and dispatch of Resources, including but not limited Resource MW capability and output, MVAR capability and output, status, and outages;
c) Locational Imbalance Prices at all nodes and designated Settlement Areas in or affecting any of Markets and Services;
d) Balancing Authority Area data, including but not limited to Balancing Authority Area demand, area control error, net scheduled interchange, actual total net interchange, and forecasts of operating reserves and peak demand;
e) Conditions or events both inside and outside market Balancing Authority Areas affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in Markets and Services;
f) Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability ("ATC") or Available Flowgate Capability ("AFC"), administration of tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;
g) Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;
h) Settlement data, including but not limited to hourly integrated settlement location MW;

i) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of Markets and Services; and
j) Generation resource operating cost data for estimating Resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses.

In addition to the monitoring of market data and information, the Market Monitor may communicate with MO Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

- Instances of Market Power

The Market Monitor will analyze market data with regard to Instances of Market Power and refer possible cases to FERC when there is sufficient credible information to warrant such action. When the case is refer to FERC, the Market Monitor is required to desist from any further action independent of FERC's investigation into the case.

The Market Monitor will keep MO and Interested Government Agencies apprised of the potential for and the implications of abusive market power behavior, and make recommendations as to how to remove the potential for and ability to exercise market power.

Specific monitoring activities regarding physical and economic withholding shall include but not be limited to assessment on (a) availability of Resources, (b) artificial barriers to entry, (c) impact of the use of Resources for reliability versus energy purposes, (d) market response to price spikes, and (e) analysis of bidding patterns. On an ongoing basis, the Market Monitor will consult with the MWG on examining other areas for instances of market power.

- Monitoring for Portfolio Bidding

The Market Monitor shall monitor MO's Markets and Services for potential abuse associated with portfolio bidding. When the Market Monitor determine there is sufficient credible information about a specific abusive practice, the issue will be referred to the Commission for further review. Two specific types of potential abusive bidding practices are described below.

D.1. Uneconomic Overproduction

The Market Monitor will look for cases where Self-dispatched Resources cause congestion on transmission facilities on the exporting side of the constraint in an uneconomic manner that are not justified by reliability concerns. The specific steps would be to:

a) Determine that the self dispatched generation is causing congestion;
b) Determine that the self dispatch is uneconomic (Resource incremental cost exceeds Resource LIP);

c) Determine that the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified in (a) to (c) and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

D.2. Strategic Withholding

The Market Monitor will look for cases where commonly owned or controlled Resources on the importing side of a transmission constraint that are required to serve the load and that are not subject to the Offer Cap, are causing the Locational Imbalance Price on the importing side of such transmission constraint to be set at levels above the Offer Cap. The specific steps would be to:

a) Identify the commonly owned or controlled Resources on the importing side of a transmission constraint that do not meet the criteria set forth under section 15.4.1 – A.2.2. (Determination of Offer Capped Resource) for imposing the Offer Cap;
b) Verify that the Resources identified in Section D.2.(a) are pivotal (i.e. are required to serve the load on the importing side of the transmission constraint);
c) Document, beginning with the EIM Market Effective Date, the Locational Imbalance Prices associated with all pivotal Resources identified under Section D.2.(b).

The Market Monitor will conduct evaluations as specified in (a) to (c) and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

- Physical Withholding

The Market Monitor will monitor participation to determine whether decisions to participate in the EIM Market have a significant adverse impact on market outcomes. If appropriate, the Market Monitor will make a referral to the Commission's Office of Enforcement (or its successor organization).

- Unavailability of Facilities

The Market Monitor will monitor for any potential instances of Unavailability of Facilities and, if appropriate, shall refer any such instances to the Commission's Office of Enforcement (or its successor organization).

14.3.3 Inquiries

A. Requests

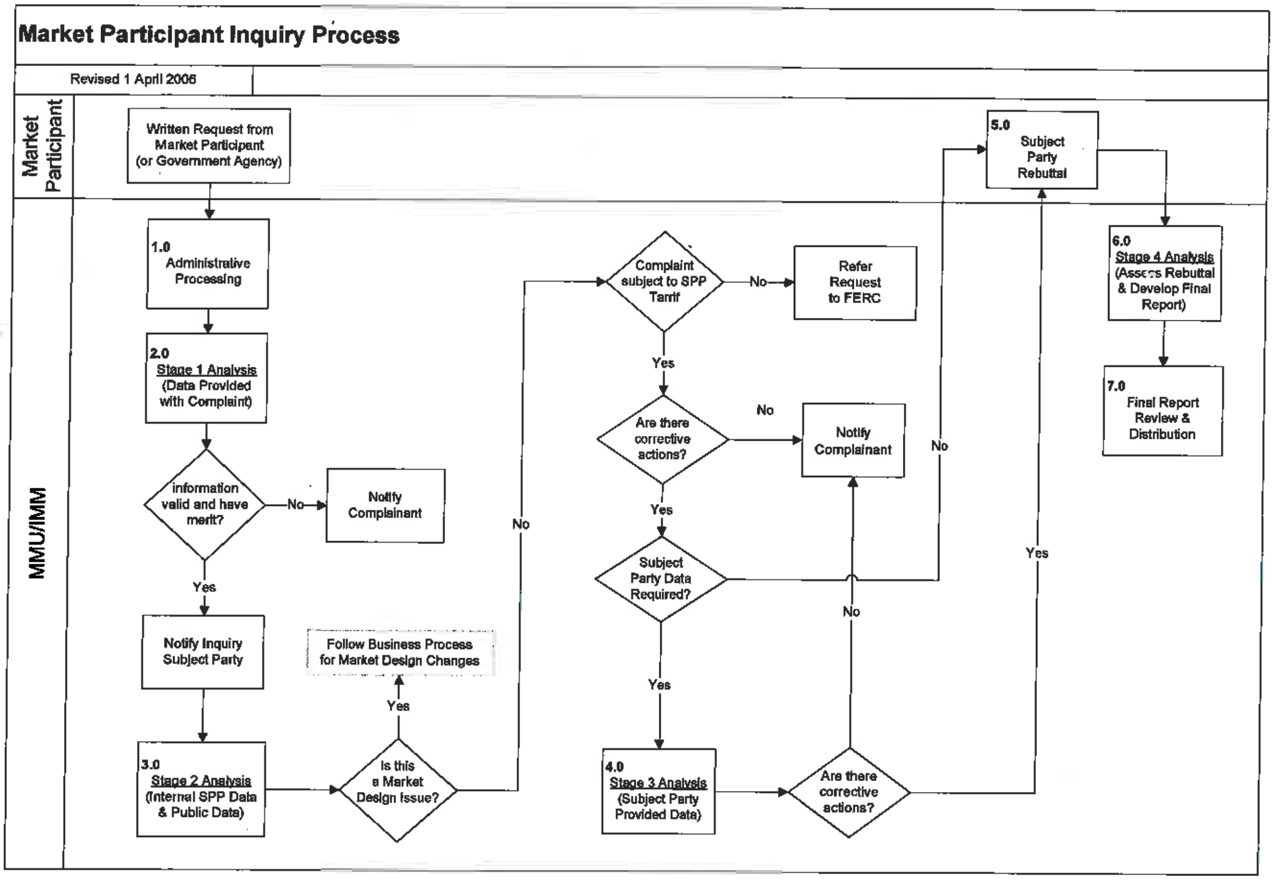
Any Market Participant or Interested Government Agency may submit in writing a complaint or request for inquiry to either Market Monitor and indicate a preference for either or both Market Monitor to perform the assessment. Upon receipt of such complaint or request, the Market Monitor receiving the request will notify the other Market Monitor, and the Market Monitor will jointly decide whether an inquiry should be conducted. As an initial screen, the Market Monitor should not pursue any complaint pertaining to issues not related to MO's Markets and Services or monitored and overseen by the Market Monitor. An inquiry will be conducted if either Market Monitor determines it should be conducted. An inquiry will not be conducted if neither Market Monitor determines it should be conducted.

Requests by Market Participants and Interested Government Agencies for the Market Monitor to conduct an inquiry can be made confidentially. The Market Monitor shall keep the identity of the requestor confidential and shall keep the existence of any inquiry conducted confidential from all uninvolved parties and from involved parties, other than the requesting party, to the extent practicable.

Nothing in this section should be interpreted as preventing the Market Monitor from conducting inquiries, either confidentially or publicly, without first receiving a complaint from a Market Participant or Interested Government Agency. The Market Monitor may initiate inquiries into any matter at any time that pertains to MO's Markets and Services that is part of their market monitoring and/or market power mitigation obligation.

B. Conducting Inquiries

The MMU has primary responsibility for conducting inquiries, unless the Market Monitor determines that the EMA should lead an inquiry. The EMA may directly participate in any inquiry lead by the MMU at either the MMU's request or its own option, but in any event, the EMA shall be regularly informed of the progress and resolution of any inquiry, and the MMU shall request the advice of the EMA during any inquiry. Market Participants shall cooperate fully with the Market Monitor during any such inquiry. The process flow chart for conducting an inquiry is shown below.


Market Participant Inquiry Process
Revised 1 April 2006
Market Participant
MMU/IMM
Written Request from Market Participant (or Government Agency)
1.0 Administrative Processing
2.0 Stage 1 Analysis (Data Provided with Complaint)
information valid and have merit?
No
Notify Complainant
Yes
Notify Inquiry Subject Party
3.0 Stage 2 Analysis (Internal SPP Data & Public Data)
Is this a Market Design Issue?
Yes
Follow Business Process for Market Design Changes
No
Complaint subject to SPP Tariff
No
Refer Request to FERC
Yes
Are there corrective actions?
No
Notify Complainant
Yes
Subject Party Data Required?
No
Yes
4.0 Stage 3 Analysis (Subject Party Provided Data)
Are there corrective actions?
No
Yes
5.0 Subject Party Rebuttal
6.0 Stage 4 Analysis (Assess Rebuttal & Develop Final Report)
7.0 Final Report Review & Distribution

C. Reporting

The Market Monitor to whom a request for inquiry was made is responsible for notifying the requesting party of the results. The Market Monitor will coordinate reporting of the results of inquiry to the Board, FERC and the RSC, as necessary. If the findings of the inquiry directly relate to any Market Participant other than the requesting party, the designated market monitoring contact of the affected Market Participant will be notified of the findings regarding his or her company. A summary of inquiries conducted and/or requested and an assessment of inquiry issues and trends will be presented in the Annual State of the Market Report were appropriate and consistent with inquiry procedures approved by the Board.

14.3.4 Compliance and Corrective Actions

A. Compliance

The Market Monitor shall administer MO's Market Monitoring Plan as described in MO's OATT Attachment ~~AG~~ XX and report any actual or potential abuse of market power or market design inefficiencies as part of its monitoring process. However, such enforcement is limited to matters that (i) are expressly set forth in MO's OATT; (ii) involve objectively-identifiable behavior; and (iii) do not subject the Market Participant to sanctions or other consequences other than those expressly approved by the Commission and set forth in the OATT. Other enforcement matters shall be subject to Commission determination in the first instance. As part of the inquiry process, the Market Monitor may issue a demand letter requesting Market Participants causing the issue to arise to change actions as the Market Monitor deem proper to achieve compliance.

The Market Monitor may also engage in discussions with persons or entities other than Market Participants that they deem may have information that may be helpful to any investigatory or compliance process.

B. Corrective Actions for Market Design

If the Market Monitor discern any weaknesses or failures in market design and protocols, including the determination that MO's Markets and Services are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure, either in the aggregate or in any portion or location thereof, the Market Monitor shall notify the appropriate Organizational Group of MO, the MO President, the RSC, appropriate state authorities, FERC Staff, and relevant Market Participants. In the event the Market Monitor believes providing such information could lead to exploitation, it will restrict such notification to the President of MO, the Chairman of the MO Oversight Committee, and FERC Staff, and will provide a justification for such limited notification. Should the appropriate MO Organizational Group not respond within 60 days, the Market Monitor may recommend changes in market design and protocols to the Board, FERC and the RSC as needed. If the appropriate MO Organizational Group responds, but does not recommend changes to market design and market rules that are acceptable to both Market Monitor, the Market Monitor shall report to the Board, and the appropriate regulatory body or bodies as needed, and then MO or the Market Monitor may file a petition or submission seeking appropriate action from FERC or any other appropriate enforcement agency. The Market Monitor shall also make recommendations for changes to MO's OATT, Criteria, and Market Protocols as necessary to correct weaknesses or failures in MO's Markets and Services.

In the event that any weaknesses or failures in market design require immediate corrective action to ensure just and reasonable prices, either Market Monitor may request the MO President to authorize an immediate FERC filing requesting implementation of a corrective action while the appropriate Organizational Group of MO responds to the Market Monitor's notification as described above. The requested immediate corrective action should be the method least intrusive or disruptive to MO's Markets and Services necessary to resolve the market weakness or failure as determined by the Market Monitor. Prior to making such a request to the MO President, the Market Monitor will make reasonable efforts to discuss with affected Market Participants and the Staff of affected Interested Government Agencies the market weakness or failure potentially requiring immediate corrective action, unless the Market Monitor determines that such discussion would lead to exploitation.

14.3.5 Reporting

The Market Monitor, with the support and input of the MWG, MO Staff, and any other MO Organizational Group, is responsible for producing (a) an Annual State of the Market Report and (b) Monthly, Quarterly and Annual Metrics Reports for assessing the efficiency, effectiveness and competitiveness of MO markets and services as requested by the MO Board of Directors or required by FERC. The Market Monitor shall have complete independence in developing and producing reports, and no person or entity may screen, alter, delete or delay the Market Monitor's findings, conclusions and recommendations. MO and Market Participants may comment on any report made pursuant to this section, through the appropriate stakeholder process. The Market Monitor shall be free to disregard suggestions with which it disagrees.

A. Annual State of the Market Report

The Annual State of the Market Report shall assess the performance of MO's Markets and Services as discussed in Section 14.2(A). Such report will discuss the progress made on the development of MO's markets and inter-RTO coordination and will include any recommendations of the Market Monitor for the improvement of MO's Markets and Services, or of the monitoring, reporting and other functions undertaken pursuant to this Protocols. The report where appropriate will also include a summary of requests for inquiries and the resolution or disposition thereof.

The report will be rendered to the Board, the Transmission Provider, Market Participants, and other interested entities. The report shall be submitted to FERC. Copies of the report shall be provided to the RSC and other appropriate state regulatory authorities on request and made publicly available by MO through a posting of the document on MO web site. Confidential information will be subject to redaction or other measures necessary for the protection of Protected Information.

B. Monthly, Quarterly and Annual Metrics Reports

The Market Monitor will prepare Monthly, Quarterly and Annual Metrics Reports. The purpose of these metrics is to provide transparency of the MO markets and to provide a standardized basis to evaluate the performance of MO's market structure and market power mitigation over time. This information will also be used to compare the performance of MO markets with that of other RTOs and ISOs. Copies of the reports shall be made publicly available by MO through posting on the MO web site, subject to redaction or other measures necessary for the protection of Confidential Information.

C. Communication of Market Monitoring Reports

Conference calls related to the Market Monitor reports may be attended by the Transmission Provider, the Board of Directors, FERC Staff and other affected regulatory authorities, Regional State Committee, and Market Participants regardless of which party initiates the conference call. The Market Monitor shall make one or more of its staff members available for regular conference calls.

D. FERC Monthly Informational Filings

FERC Order Docket No. ER06-451-000 required MO Market Monitor to file monthly informational reports on three subjects for the first year of the MO EIM market that started on February 1, 2007. The last required filing will cover the month of January 2008. The three areas to be covered in the monthly filings include depth of market, congestion resolution, and effects of under scheduling.

1. Depth of EIM Market

The Market Monitor will monitor the effects of self-dispatch on the depth of the EIM Market, for one year following the EIM Market Effective Date. The Market Monitor shall make monthly information filings to the Commission regarding total megawatts of bids at each node relative to the available megawatts of generation at each node.

2. Congestion Resolution

The Market Monitor will develop detail assessments on how congestion and imbalance were resolved, whether through UFMP, Congestion Management Events or imbalance market mechanisms. This information will be filed monthly with the Commission for one year following the EIM Market Effective Date.

3. Effects of Under Scheduling

For one year following the EIM Market Effective Date, the Market Monitor shall identify over and under-scheduling relative to the Market Participant's Reported Load when congestion occurs, and submit monthly reports to the Commission on the benefits gained by those Market

Participants, the Over Scheduling Charges and Under Scheduling Charges made to Market Participants, and any other issues the Market Monitor deems relevant to over and under-scheduling. As a component of this reporting, the Market Monitor shall determine, and recommend if needed changes to the Market Protocols to address any significant issues presented by this ongoing review.

E. Other Reports

The Market Monitor shall prepare other reports or briefings on matters within their responsibility as may be requested by the Board or FERC, or as they deem necessary.

14.3.6 Performance Indices, Metrics and Screens

Performance indices, metrics and screens form the necessary objective basis for observing the functioning of MO's Markets and Services, including the conduct of Market Participants in such markets, and for providing reports and market analyses.

A. Development

The Market Monitor, with the assistance and input of the MWG and the RSC, will develop performance indices, metrics and screens for reviewing market data and other information collected. Consideration should be given to the inter-RTO metrics in use by other RTOs, ISOs and the FERC during such development.

B. Implementation

Whenever practicable, the Market Monitor should review data or other information collected in accordance with the adopted indices, metrics and screens. However, the Market Monitor shall not be prevented from conducting further or different review or evaluation of such data as deemed appropriate.

14.3.7 Market Behavior Rules

All suppliers with market-based rates are required to comply with the Market Behavior Rules defined in FERC Order No. 670 and the Conditions for Public Utility Market-Based Rate Authorization Holders defined in FERC Order No. 674, as they may be amended from time to time. The Market Monitor shall monitor for violations of these rules and report any suspected violations to FERC Staff in accordance with the FERC's reporting protocols for market monitor in a timely manner. Market Participants are required to abide by these market behavior rules.

The Market Monitor shall monitor for violations of these rules or any other Commission-approved rules and regulations, or of MO's Tariff and report any suspected violations by Market Participants or MO to FERC's Office of Enforcement (or its successor organization) staff in accordance with the FERC's reporting protocols for referral by market monitors as specified in 18 CFR 35.28(g)(3)(iv) in a timely manner. Any such reports by the Market Monitor to FERC Staff shall be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release, unless such information and documents are already in the public domain.

14.3.8 Market Manipulation

The Market Monitor will monitor the EIM Market for potential instances of market manipulation. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeable could manipulate market prices, market conditions, or market rules for electric energy or electric products are prohibited. Potential behavior activities of concern include: (a) wash trades, (b) submission of false data, (c) actions to cause artificial congestion, and (d) collusive acts. The Market Monitor will report to FERC any potential market manipulation in the EIM Market in a timely manner.

14.3.9 Monitoring for Potential Transmission Market Power Activities

The Market Monitor shall monitor MO's Markets and Services for potential transmission market power activities by reviewing and analyzing data and information related to the availability of transmission facilities that impact access particularly with respect to the withholding of transmission facilities or transmission capacity, including activities such as but not limited to, the following:

a) Physical withholding by Transmission Owners by providing improper information related to the availability of transmission, such as information related to the capability or other modeling data used by MO for use in system operations:
b) Economic withholding by Transmission Owners through the use of methods and data for estimating costs of interconnection and system upgrades that is not comparable for affiliates and non-affiliates;
c) Unavailability of transmission facilities through planned and unplanned maintenance outages that routinely exceed historical baselines.
d) Withholding of transmission capacity by transmission users through excess reservations

that are not actually used.

The Market Monitor shall refer any instance(s) of potential transmission market power directly to FERC utilizing the protocols for referral to the Commission for suspect market violations and perceived and perceived market design flaws and recommend tariff language changes as found in 18 CFR 35.28(g)(3)(iv). Where appropriate, the Market Monitor shall also provide the FERC with an estimate of damages equal to (i) the effect on prices multiplied by (ii) the affected energy produced by the Transmission /Generation Owner. All such referrals by the Market Monitor to FERC will be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release.

14.3.10 Data Access, Collection and Retention

The Market Monitor shall regularly collect and maintain Data and Information necessary for monitoring MO's Markets and Services and implementing mitigation protocols.

A. Confidentiality

Market Monitor is subject to and will abide by the confidential rules as delineated in the MO OATT.

B. Access to MO Data and Information

The Market Monitor shall have access to all Data and Information gathered or generated by MO in the course of its operations. This Data and Information shall include, but not be limited to, that listed in the Market Monitoring section of these protocols. All Data and Information listed in the Market Monitoring section shall be retained by MO for a minimum period of three years.

C. Access to Market Participant Data and Information

Market Participants shall retain all Data and Information listed below, and in Section 15.3.3 of this Plan as applicable, that is in the custody and control of Market Participants, for a minimum of three years and will promptly provide any such Data and Information to the Market Monitor upon request. Market Participants shall be capable, upon request, of providing the Data in native format and a description of the format used by the MP. If necessary, due to proprietary format restrictions, the MP shall be capable of providing the data in a non-proprietary format, such as CSV or XML format.

Data and Information to be retained by Market Participants and provided to the Market Monitor upon request:

a) All Data and Information relating to the costs of operating a Resource, including but not limited to, heat rates, start-up fuel requirements, fuel purchase costs, environmental costs, and operating and maintenance expenses;

b) All Data and Information regarding opportunity costs of a Resource, including but not limited to, regulatory, environmental, technical, or other restrictions that limit the run-time or other Resource operating characteristics;

c) All Data and Information relating to the operating status of a Resource, including Resource logs showing the generating status of a specified unit, including information relating to a forced outage, planned outage or derating of a Resource;

d) All Data and Information relating to the operating status of a transmission facility, a contingency, or other operating consideration, including forced outages, planned outages or derating of a transmission system component;

e) All Data and Information relating to transmission system planning, including studies, reports, plans, models, analyses, and filings with FERC or any state regulatory commission;

f) All Data and Information relating to the ability of a Market Participant or its Affiliate to determine the pricing or output level of generating capacity owned by another entity, including but not limited to any document setting forth the terms or conditions of such ability.

g) All Data and Information used in the course of business operations in arriving at a decision by a Reserve Sharing Group (RSG) member to call an Operating Reserve Contingency and request assistance.

If any additional Data and Information not listed above or in the Market Monitoring section of these protocols is required from Market Participants by the Market Monitor for the purpose of fulfilling its responsibilities, the Market Monitor may request such Data and Information from Market Participants. Such Data and Information shall be provided in a timely manner by Market Participants. Any such request shall be accompanied by an explanation of the need for such data or other information, a specification of the form or format in which the data is to be produced, and an acknowledgement of the obligation of the Market Monitor to maintain the confidentiality of the data.

If a Market Participant receiving a request for Data and Information not listed above or in the Market Monitoring section of these protocols believes that production of the requested Data and Information would impose a substantial burden or expense, or would require the party to produce information that is not relevant to achieving the purposes or objectives of these market monitoring protocols, the Market Participant receiving the request shall promptly so notify the Market Monitor. The Market Monitor shall review the request with the receiving Market Participant to determine whether, without unduly compromising the objectives of these market monitoring protocols, the request can be narrowed or otherwise modified to reduce the burden or expense of compliance, and if so shall so modify the request. No party that is the subject of a data request shall be required to produce any summaries, analyses or reports of the data that do not exist at the time of the data request.

If the Market Monitor determines that the requested Data and Information has not or will not be provided in a timely manner, the Market Monitor may utilize (a) MO's dispute resolution procedures in its OATT or Bylaws as applicable or (b) a filing with the appropriate regulatory or enforcement agency to compel the production of the requested information.

D. Data Created by Market Monitor

Any data created by the Market Monitor, including any reconfiguration of Data and Information obtained from MO or Market Participants, will remain within the Market Monitor's exclusive control. Such data may be shared with MO and Market Participants at the Market Monitor's sole discretion and on a non-discriminatory basis, subject to the confidentiality provisions specified in the MO's OATT ~~Section 8.1 of Attachment AG and Section 8 of Attachment AE~~.

14.3.11 Miscellaneous Provisions

A. Rights and Remedies

This Plan does not restrict MO and Market Participants from asserting any rights they may have under state and federal regulation and laws, including initiating proceedings before the FERC regarding any matter which is subject to this Plan.

B. Disputes

Disputes as to the implementation of, or compliance with, this Plan shall be subject to the dispute resolution procedures under the MO Tariff or under the MO Bylaws as applicable or subject to review by FERC.

C. Review of Market Monitor

The activities of the Market Monitor shall be reviewed from time to time by the Board of Directors.

14.4 Market Power Mitigation

14.4.1 Purpose and Definitions

A. Purpose and Objective

The Transmission Provider shall implement these Market Mitigation Protocols in conjunction with the Market Mitigation Plan in Attachment ~~AF~~ XX of the MO OATT. The CAISO's tariff provisions regarding market power mitigation are contained in section 39 of the tariff. The following description from SPP's straw proposal illustrates the general principles that are performed by a similar market power mitigation mechanism.

There are two basic themes with regard to market power mitigation. First, mitigation measures must offer the opportunity for extensive intervention in energy markets, if necessary, to suppress price spikes resulting from the exercise of market power. Mitigation Measures is meant to block generators with the potential for market power abuse from bidding above the price level that would otherwise prevail in a competitive market. Second, that intervention must explicitly be balanced with the goal of assuring system reliability in the long term.

B. Definitions

Generator-to-Load Distribution Factor – The simulated impact of incremental power output from a specific Resource ("source") on the loading of a specific flowgate based on delivery to a representation of the locational weighting of all loads within all Settlement Locations ("sink").

14.4.2 Economic Withholding

A. Energy Market Power

A.1. Principles

There are two principles for mitigating Economic Withholding in the EIM Market operated by MO.

A.1.1. Mitigate Only During Transmission Constraints

The electricity marketplace in the MO Region is workably competitive, with an adequate supply of electricity and diversity of suppliers, absent transmission constraints that may balkanize the region. Therefore, mitigation will be applied only at the time of, and in places with, transmission constraints.

A.1.2. Do Not Mitigate Below Long Run Marginal Cost of New Investment

Mitigation should not create or exacerbate a shortage by capping prices below the level needed to attract investment that would relieve the shortage. This level shall be based on the long run marginal cost of the least-cost generation supply that could be developed within the shortest period of time, which is currently a new, natural gas-fired combustion turbine, peaking Resource.

A.2. Mitigation Measure

When any transmission constraint is binding in the EIM Market, the Offer Curve associated with Resources on the importing side of each constraint and Generator-to-Load Distribution Factors that are equal to or greater than 5% shall have an effective offer no higher than the Offer Cap for each Resource. The effective offer is what the Market Operating System uses in determining prices and dispatch directions.

A.2.1. Location and Determination of Binding Constraints

Binding transmission constraints in the EIM Market will be located on groups of transmission elements designated as flowgates. The determination of whether a transmission constraint is binding in the EIM Market will be based on the MO Congestion Management process and the EIM Market security constrained dispatch process for such determination.

A.2.2. Determination of Offer Capped Resources

An Offer Cap , as calculated in accordance with Section A.2.4 below, shall apply to certain Resources, regardless of ownership, that are on the same side of a constrained flowgate as the constrained load and within electrical proximity to the constrained flowgate. Such Resources subject to the Offer Cap will be determined for each flowgate through the use of the Generator-to-Load Distribution Factors (GLDF). All Resources that are located on the importing side (side with the constrained load) of a constrained flowgate that have GLDF greater than or equal to 5% (i.e., for each 100 MW increase in Resource output, the imports across the flowgate are reduced by 5 MWs or greater) shall be subject to an Offer Cap. If any of a Market Participant's Resources are subject to the Offer Cap based on the GLDF, all Resources owned by that Market Participant that are located on the importing side of the same constrained flowgate shall also be subject to an Offer Cap. A list of all Resources subject to an Offer Cap shall be posted electronically, daily, at the www.MO.org website for each flowgate.

GLDF values will be reassessed at least once a year. GLDF values will also be reviewed and revised if needed when there are significant changes to the transmission grid within or affecting MO EIM Market area.

A.2.3.3. Reassessment of Offer Capped Status

The Transmission Provider will reassess the status of Resources subject to Offer Caps when transmission and Resource additions, changes, outages, or changes in ownership occur that may reasonably cause the Resources' Offer Capped status to change. In any event, the Transmission Provider will reassess the status of Offer Capped Resources on an annual basis.

A.2.4. Calculation of Offer Caps

The Offer Cap for each Resource subject to an Offer Cap will be calculated daily, posted at the www.MO.org website for such Resource, and will be effective until replaced by a new Offer Cap. Specifically, Offer Caps will be equal to the sum of (a) the estimated annual fixed cost of a new, natural gas-fired, combustion turbine peaking generation facility in $/megawatt-year divided by the annual hours of constraint, (b) an adder equal to the estimated non-fuel variable operation and maintenance costs of a new, natural gas-fired, combustion turbine peaking generation facility in $/megawatt-hour, and (c) the fuel cost of the peaking facility in $/megawatt-hour calculated as the heat rate multiplied by a natural gas price index. The formula for the calculation is as follows:

$$\text{Offer Cap} = (AFC / AHC) + VOM + FC$$

Wherein the variables are defined as:

AFC = Annual Fixed Cost (Annual Investment Recovery Requirement ($/megawatt-year) + Annual Fixed Operations and Maintenance Adder ($/megawatt-year))

AHC = Annual Hours of Constraint

VOM = Variable Non-Fuel Operations and Maintenance Adder ($/megawatt-hour)

FC = Fuel Cost (Heat Rate * Natural Gas Price Index) ($/megawatt-hour)

Offer Caps do not function as price caps on the EIM Market because some Resources may not subject to an Offer Cap and there are other factors that affect prices such as congestion costs. Resources not subject to an Offer Cap may bid higher than, and set a price in the EIM Market that is above an Offer Cap for another Resource. During periods of constraint on flowgates, the market operating system limits the effective offer curve used in determining LIP to a maximum equal to Offer Caps for a Resource subject to the Offer Cap. All Resources, including those Resources identified subject to Offer Caps, will be charged/compensated based upon the Locational Imbalance Price associated with each Resource.

A.2.4.1. Annual Fixed Cost

The annual fixed cost of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the calculated value of the annual carrying cost associated with the recovery of the total fixed costs to develop, build and finance such a facility plus the fixed operation and maintenance costs. Such cost shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the Commission for approval after such review. Such costs, along with any studies justifying the costs, shall be reflected in the Tariff and posted electronically by MO. The Annual Fixed Cost currently approved by the Commission and contained in the MO OATT is $68,640/Megawatt-year.

A.2.4.2. Variable Non-Fuel O&M Adder

The adder equal to the estimated non-fuel variable operation and maintenance costs of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the non-fuel operating and maintenance costs of such a facility not included in the calculation of annual fixed costs as described above. Such cost shall be reviewed annually by the Transmission Provider with input from Market Participants. Any changes to such costs, along with justification for the changes, shall be filed with the FERC for approval after such review. Such costs, along with any studies justifying the costs, shall be reflected in the Tariff and posted electronically by MO. The current approved rate contained in the MO OATT is $3.43/Megawatt-hour.

A.2.4.3. Annual Hours of Constraint

The annual hours of constraint will be calculated individually for each Resource subject to an Offer Cap and will be based on the most recent 365 days (366 days for a leap year) of total hours of constraint in the EIM Market for constrained flowgates affecting the Resource. In the event that multiple constraints simultaneously affect a Resource, coincident hours of constraint will be only be counted as one hour for the Offer Cap calculation for such a Resource.

During the first year of operation of the EIM Market, the hours of duration for UFMP and Congestion Management Event Level 3 and above events for each flowgate shall be used as a proxy for hours of constraint in the EIM Market. For each flowgate, this proxy shall apply for the period prior to the start of the EIM Market that is included in the 12 month rolling sum calculation of annual hours of constraint. The annual hours of constraint will be updated daily for inclusion in the daily calculation of the Offer Cap on each Resource and will be posted electronically by MO for each Resource on the www.MO.org website.

A.2.4.3.1 New Flowgates

When a new flowgate is established, the annual hours of constraint used in the calculation of the Offer Cap for each Resource that is pivotal to the new flowgate will be 32 hours until the actual number of hours of constraint on the flowgate has exceeded 32 or the flowgate has been established for at least 12 months. Thereafter, the actual hours of constraint will be used for the 12 month rolling sum. If a Resource is pivotal on a new flowgate, in addition to other established flowgates, the annual hours of constraint for the Resource will be the higher of the actual hours of constraint or 32 hours until the new flowgate has been established for at least 12 months.

A.2.4.4. Fuel Cost

The fuel cost of a new, natural gas-fired, combustion turbine peaking generation facility shall be based on the estimated full-load heat rate of the facility multiplied by a fuel price index. The fuel price index for each Resource will be based on an industry accepted natural gas pricing index for the natural gas pricing point nearest to the Offer Capped Resource(s) of each Market Participant. The fuel price shall be further modified based on an estimate of the distribution cost for moving natural gas to the Offer Capped Resource(s). Alternative pricing points and fuel price modifiers shall be evaluated annually by the Transmission Provider with input from Market Participants. The fuel price portion of each Offer Cap shall be recalculated daily for inclusion in each Offer Cap and posted daily on the MO.org website. The current approved heat rate contained in the MO OATT is 10,450 Btu/kilowatt-hour.

A.3 Imposition of Mitigation

Offer Caps will be imposed when any transmission constraint is binding in the EIM Market as determined by MO's Market Operators through the MO Congestion Management process and the EIM Market security constrained dispatch process

A.3.1. Offer Cap Revisions

Market Participants with Offer Capped Resources may request an exception to an Offer Cap for a Resource. If the Market Participant, after consultation with the Market Monitor determines that an exception is reasonable, shall submit a filing with the Commission.

14.4.3 "Safety-Net" Offer Cap and Offer Floor

Beginning 91 days after the EIM Market Effective Date, submission of Offer Curves by Market Participants will be limited to less than or equal to $1000/megawatt-hour. This limit will remain in effect until such time as MO demonstrates in a filing with the Commission that sufficient demand response exists in the EIM Market to allow a higher Offer Curve price limit or removal of the Safety-Net Offer Curve price limit.
In addition, submitted Offer Curves will be limited to greater than or equal to negative $1000/megawatt-hour. Pending software changes to systematically reject Offer Curves below the offer floor, MO will notify the Market Participant that the submitted Offer Curve is invalid. In the event an Offer Curve is not corrected and LIPs are affected, MO shall revise LIPs pursuant to the procedure outlined in Section 13.3.2.

14.4.4 Maintenance and Implementation of the Mitigation Protocols

The Transmission Provider is responsible for implementing the market power mitigation measures as approved by FERC. The Transmission Provider is also responsible for periodically reviewing and recommending revisions to the mitigation protocols and supporting MO Regulatory Staff in obtaining approval from FERC for any such updates with input and support from the MWG.

15 Process for Protocol Revision Requests

The process for changes to the Energy Imbalance Protocols is a topic to be addressed along with the overall EIM governance structure. Multiple organizational models are possible, including (1) the change management process for the California ISO's Business Practice

Manuals, as described in its Business Practice Manual for Change Management (available at https://bpm.caiso.com/bpm/bpm/version/000000000000012), and the process used by the Southwest Power Pool, which is described in the remainder of this Section 15.

15.1 Introduction

A request to make additions, edits, deletions, revisions, or clarifications to these Protocols, including any attachments and exhibits to these Protocols, is called a "Protocol Revision Request" (PRR). Unless specifically provided in other Sections of these Protocols, this Section shall be followed for all PRRs.

All decisions of the Market Working Group (MWG), and the Market and Operations Policy Subcommittee (MOPC) and the MO Board with respect to any PRR shall be posted to the MO Web Site within three (3) Business Days of the date of the decision. All such postings shall be maintained on the MO Web Site for at least one hundred eighty (180) days from the date of posting.

The "next regularly scheduled meeting" of the MWG, MOPC or the MO Board shall mean the next regularly scheduled meeting for which required notice can be timely given regarding the item(s) to be addressed, as specified in the appropriate Board, committee, or working procedures.

15.2 Submission of a Protocol Revision Request

The following Entities may submit a PRR:

(1) Any Market Participant;

(2) Any Entity that is an MO Member;

(3) Any staff member of a governmental authority having jurisdiction over the MO or any member company; and

(4) MO Staff

(5) MO Independent Market Monitor

(6) Any MO Committee or Working Group

15.3 Protocol Revision Procedure

15.3.1 Review and Posting of Protocol Revision Requests

PRRs shall be submitted electronically to MO by completing the designated form provided at the MO Web Site (PRR Request/Comment Forms). All PRRs are to be submitted to the email address found on the MO Web Site (protocolrevisions@MO.org). Any PRRs not submitted appropriately will not be processed.

The PRR shall include the following information:

(1) description of requested revision;

(2) reason for the suggested change;

(3) impacts and benefits of the suggested change on MO market structure, MO operations, and Market Participants, to the extent that the submitter may know this information;

(4) PRR Impact Analysis (PIA) (applicable only for a PRR submitted by MO Staff);

(5) list of affected Protocol Sections and subsections;

(6) list of affected Tariff, Business Practice or Criteria sections;

(6) general administrative information (organization, contact name, etc.); and

(7) suggested language for requested revision.

MO shall evaluate the PRR for completeness and shall notify the submitter, within five (5) Business Days of receipt, if the PRR is incomplete, including the reasons for such status. MO may provide information to the submitter that will correct the PRR and render it complete. An incomplete PRR shall not receive further consideration until it is completed. In order to pursue the revision requested, a submitter must submit a completed version of the PRR with the deficiencies corrected.

If a submitted PRR is complete or once a PRR is corrected, MO shall post a complete PRR to the MO Web Site and distribute the PRR to the MWG within three (3) Business Days.

15.3.2 Comments on a PRR

Any interested entity that is qualified to submit a protocol revision request may comment on a PRR. To receive consideration, comments on the PRR must be delivered electronically to MO in the designated format provided on the MO Web Site within fourteen (14) days from the date of posting/distribution of the PRR. Comments submitted after the due date of the fourteen (14) day comment period may be considered at the discretion of MWG.

Within one (1) Business Day of receipt of comments related to the PRR, MO shall post such comments to the MO Web Site. The comments shall include identification of the commenting Entity.

Comments submitted in accordance with the instructions on the MO Web Site—regardless of date of submission—shall be posted to the MO Web Site and distributed electronically to the MWG within one (1) Business Day of submittal.

MWG shall review the PRR and any posted comments to the PRR at its next regularly scheduled meeting after the end of the fourteen (14) day comment period, unless the fourteen (14) day comment period ends less than three (3) days prior to the next regularly scheduled MWG meeting. In that case, the PRR will be reviewed at the subsequent regularly scheduled MWG meeting.

15.3.3 Operations Reliability Working Group Review

The ORWG may review PRRs and submit comments for MWG's consideration prior to the MWG's review or MWG taking action on a PRR.

Upon notification of the posting of a PRR Recommendation Report, the ORWG shall review the recommended changes to determine if the proposed change conflicts with requirements outlined in the MO Criteria. In the event the ORWG identifies what it believes are conflicts with the MO Criteria, which have not previously been identified by the MWG, or issues concerning the proposed changes, the ORWG will submit comments to the PRR to be considered by MWG at its next regularly scheduled meeting or by MOPC during its review of the Recommendation Report.

15.3.4 Regional Tariff Working Group Review

The RTWG may review PRRs and submit comments for MWG's consideration prior to the MWG's review or MWG taking action on a PRR.

Upon notification of the posting of a PRR Recommendation Report, the RTWG shall review the recommended changes to determine if the proposed change conflicts with requirements outlined in the Tariff. The RTWG shall review and provide comments on any proposed Tariff changes included in the Recommendation Report. In the event the RTWG identifies what it believes are conflicts with the Tariff, which have not previously been identified by the MWG, or issues regarding the proposed changes, the RTWG will submit comments to the PRR to be considered by the MWG at its next regularly scheduled meeting or by the MOPC during its review of the Recommendation Report.

15.3.5 Initial Impact Analysis

MO staff shall submit a Protocol Revision Request Impact Analysis (PIA), or indicate one is not necessary on the PRR, with any PRR that MO staff submits to the MWG based on the original language in the PRR. The PIA will provide MWG with guidance as to what computer systems, operations, or business functions could be affected by the PRR as submitted.

A PIA should assess the impact of the proposed PRR on MO computer systems, operations, or business functions and shall contain the following information:

(1) an estimate of any cost and budgetary impacts to MO for both implementation and on-going operations;

(2) the estimated amount of time required to implement the revised Protocol language;

(3) the identification of alternatives to the original proposed language that may result in more efficient implementation;

(4) the identification of any manual workarounds that may be used as an interim solution and estimated costs of the workaround; and

(5) verification of review (if necessary) of the PRR by the Credit Working Group and the impact of its review on the PIA.

(6) the identification of any additional changes to the Tariff , MO Criteria, or Business practices that are required prior to the implementation of the PRR

Upon receipt of a PRR submitted by any Entity other than MO, MO shall perform an initial evaluation of the impact on MO and include the evaluation in MO's comments. The initial evaluation will provide MWG with guidance as to what computer systems, operations, or business functions could be affected by the PRR as submitted. MO shall post its comments prior to the MWG initial review of the PRR, if practicable.

15.3.6 Market Working Group Review and Action

The MWG is to review and recommend action to the MOPC on formally submitted PRRs.

The MWG may take action on the PRR to:

(1) recommend approval as submitted or modified, which approval may be subject to review of a PIA or updated PIA if such review is determined by MWG to be necessary;

(2) reject. A PRR shall be considered rejected if a majority of MWG members fail both to reject and approve the PRR, either as submitted or modified

(3) defer action on the PRR; or

(4) refer the PRR to a workgroup, or task force it deems appropriate. The PRR may be referred to a task force created by MWG and/or to one or more existing working groups or task forces of MOPC for review and comment on the PRR. Suggested modifications—or alternative modifications if a consensus

recommendation is not achieved by a non-voting working group or task force—to the PRR should be submitted by the chair or the chair's designee on behalf of the working group or task force as comments on the PRR for consideration by MWG. However, the MWG shall retain ultimate responsibility for the processing of all PRRs.

Within three (3) Business Days after MWG takes action to approve, approve with modifications, or reject the PRR, MO shall post a report ("PRR Recommendation Report") to the MO Web Site reflecting the MWG action. Where a PRR has been approved subject to review of a new or updated PIA, the recommendation report shall be titled "Preliminary PRR Recommendation Report." The MO shall notify the Operations Reliability Working Group (ORWG) and the Regional Tariff Working Groups (RTWG) via e-mail of the posting of PRR recommendation reports. A PRR recommendation report shall contain the following items:

(1) identification of submitter;

(2) modified Protocol, Criteria and Tariff language proposed by the MWG;

(3) identification of authorship of comments;

(4) proposed effective date(s) of the PRR;

(5) priority and rank for any PRRs requiring a system change project; and

(6) recommended action: approval, approval with modified language, or approval subject to review of an Updated Protocol Revision Request Impact Analysis.

(7) whether or not a new or updated PIA is required prior to forwarding the PRR Recommendation Report to MOPC for review.

The MWG Chair shall notify MOPC of PRRs rejected by MWG.

15.3.7 Updated Protocol Revision Request Impact Analysis and MWG Action

If MWG approves a PRR contingent upon review of a new or updated PIA, MO staff shall prepare a PIA based on the PRR Recommendation Report to identify and evaluate the required changes to the MO Systems and staffing needs, including, but not limited to, MO's operating systems, settlement systems, business functions, operating practices, MO System operations, and staffing needs.

Unless a longer review period is warranted due to the complexity of the proposed PRR Recommendation Report or the quantity of approved PRRs, MO shall issue the PIA for the recommended PRR within twenty-five (25) days after MWG approval of the PRR. MO shall post the results of the completed PIA on the MO Web Site. If a longer review period is required for MO Staff to complete a full PIA, MO Staff shall submit a schedule for completion of the PIA to the MWG chair.

MWG shall consider the Updated PIA at the first regular meeting after the completion of the Updated PIA, or at such earlier date after completion of the Updated PIA established by the chair of MWG. At such meeting, MWG shall either:

(1) recommend final approval of the PRR as set forth in the initial PRR Recommendation Report or as modified, which recommendation may be subject to further evaluation of impacts as directed by MWG;
(2) reject the PRR. A PRR shall be considered rejected and appealable if a majority of MOPC members fail both to approve the PRR, either as submitted or modified, and reject the PRR;
(3) defer action on the PRR;
(4) refer the PRR to a workgroup or task force as MWG deems appropriate.

After consideration of the Updated PIA, a revised PRR Recommendation Report shall be issued by MWG to MOPC and posted on the MO Web Site. Additional comments received regarding the revised PRR Recommendation Report shall be accepted up to three (3) Business Days prior to the MOPC meeting at which the PRR is scheduled for consideration. If MWG revises its initial recommendation, MO may issue an updated PIA at least three (3) Business Days prior to the regularly scheduled MOPC meeting. If a longer review period is required for MO Staff to update the PIA, MO Staff shall submit a schedule for completion of the PIA to the MOPC chair.

15.3.8 Withdrawal of Protocol Revision Request

Upon notice to the MWG, the submitter of a PRR may withdraw the PRR at any time prior to final approval of the PRR by the MWG. MO shall post a notice of the submitter's withdrawal of a PRR on the MO Web Site within one (1) Business Day of the submitter's notice to MWG.

Once finally approved by the MWG a PRR cannot be withdrawn except with approval of the MOPC.

15.3.9 Expedited Review Requests

The party submitting a PRR may request that the PRR be considered for Expedited Review when the submitter is requesting action from the MWG on a PRR that has not met the minimum comment period described in Section 15.3.2.

A valid motion in a regularly scheduled meeting of the MWG is required to waive the minimum comment period and treat a PRR with Expedited Review status.

If approved for Expedited Review by the MWG, the PRR will be treated the same as one that has met the minimum comment period. If the request for Expedited Review is rejected, the PRR will be considered by the MWG after the minimum period; in most cases at the next regularly scheduled MWG meeting.

15.3.10 Urgent Action Requests

The party submitting a PRR may request that the PRR be considered for Urgent Action. Urgent Action Requests should be reserved for instances when existing Protocol is impairing or could imminently impair MO System reliability or wholesale or retail market operations, or is causing or could imminently cause a discrepancy between any of MO's governing documents.

The MWG shall consider the Urgent Action PRR at its earliest regularly scheduled meeting or at a special meeting called by the MWG chair. In some cases, an Urgent Action Request will occur concurrently with an Expedited Review Request. A valid motion and vote of the MWG are required to designate the PRR for Urgent Action. After approval, Urgent Action PRRs shall be given priority high enough to ensure implementation within the timeline necessary to mitigate concerns about MO system reliability or market operations under the unmodified language, or any other significant issues identified in the PRR.

If approved, MO shall submit an Urgent Action PRR Recommendation Report to the chair and staff secretary of the MOPC, RTWG, and ORWG within 2 business days to address the urgency of the PRR. The MOPC, RTWG and ORWG chairs may request action from the working groups to address the urgency of the PRR.

15.3.11 Appeal of Decision

If MWG rejects the PRR, any entity eligible to submit a PRR may appeal directly to the MOPC. Such appeal to the MOPC must be submitted to MO within ten (10) Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the MOPC shall be posted on the MO Web Site within three (3) Business Days and placed on the agenda of the next available regularly scheduled MOPC meeting, provided that the appeal is provided to MO at least eleven (11) days in advance of the MOPC meeting; otherwise the appeal will be heard by the MOPC at the next regularly scheduled MOPC meeting.

If MOPC rejects the PRR, any entity eligible to submit a PRR may appeal directly to the MO Board. Such appeal to the MO Board must be submitted to MO within ten (10) Business Days after the date of the relevant decision. Appeals made after this time shall be rejected. Appeals to the MO Board shall be posted on the MO Web Site within three (3) Business Days and placed on the agenda of the next available regularly scheduled MO Board meeting, provided that the appeal is provided to the MO General Counsel at least eleven (11) days in advance of the Board meeting; otherwise the appeal will be heard by the Board at the next regularly scheduled Board meeting.

15.3.12 Market and Operations Policy Committee Action

MOPC shall consider any PRRs that MWG has submitted to MOPC for consideration for which a final PRR Recommendation Report has been posted on the MO Web Site for at least six (6) days or those accepted for expedited treatment by the MOPC. The following information must be included for each PRR considered by MOPC:

(1) the PRR Recommendation Report and PIA, if any; and

(2) any comments timely received in response to the PRR Recommendation Report.

MOPC shall take one of the following actions regarding the PRR Recommendation Report:

(1) approve the PRR as recommended in the PRR Recommendation Report or as modified by MOPC;

(2) reject the PRR. A PRR shall be considered rejected if MOPC members fail both to reject or approve the PRR, either as submitted or modified; or

(3) remand the PRR to the MWG with instructions.

If the PRR Recommendation Report is approved by the MOPC, as recommended by MWG or modified, the MOPC shall review and approve or modify the proposed effective date. The MOPC's decision regarding approval or rejection of a PRR shall be posted on the MO Web Site within three (3) Business Days after the MOPC's decision.

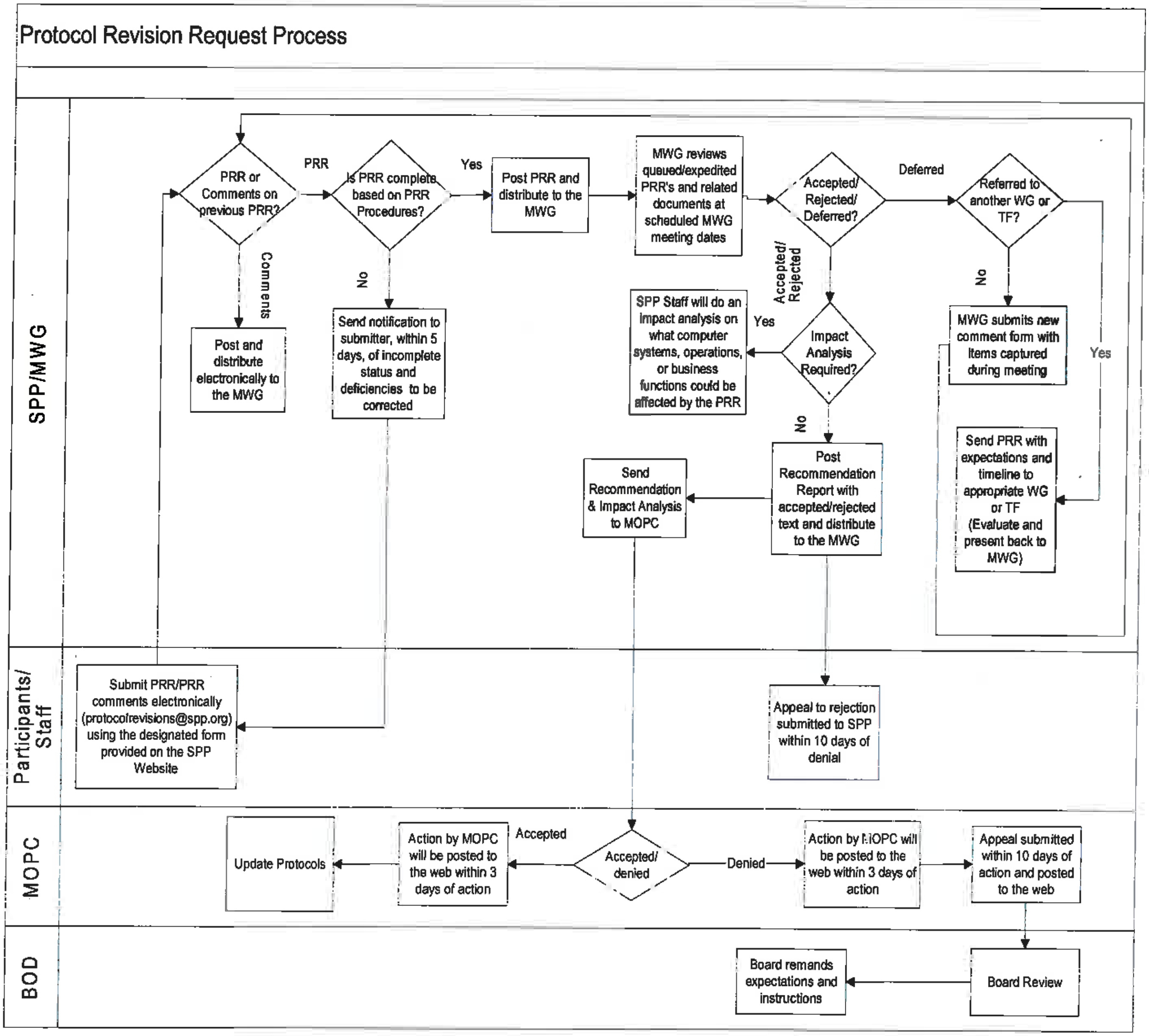
If the MOPC approves a change or changes to the Protocols, such change(s) shall be:

(1) posted on the MO Web Site as a MOPC Action Report and

(2) incorporated into the Protocols posted on the MO Web Site as soon as practicable, but no later than one (1) day before the effective date of the changes. Where a PRR does not take effect immediately, the PRR shall be shown in the Protocols in gray-boxed text that indicates the anticipated effective date of the PRR. At least two times per year, MWG shall review all PRRs in gray-boxed text and determine whether it is necessary to adjust the anticipated effective date of any PRR. MWG's decision to

adjust an effective date may be appealed to MOPC and/or the Board in accordance with the provisions for appeal of a rejected PRR.

15.3.13 Process Flow Chart for Protocol Revision Requests



16 Market Process and System Change Process

The release planning process assesses market initiative implementation impacts to determine target timeframes, project milestones and other resource considerations. It is a collaborative process between the Market Operator and market participants to optimize the costs and benefits of the implementation approach prior to committing resources. As with the Protocol Revision Process described in Section 15, the release planning process for changes to the EIM market systems is a topic to be addressed along with the overall EIM governance structure, for which multiple organizational models are possible. The California ISO's process is coordinated with market participants through activities accessible through its Release Planning Process web page at http://www.caiso.com/informed/Pages/ReleasePlanning/Default.aspx, and includes:

- Program Lifecycle Methodology documentation,
- bimonthly Market Performance and Planning Forums to involve a broad set of stakeholders in release planning,
- Release User Group for coordination of project milestones and deliverables through twice-per-month web conferences,
- Technical User Group for identification, discussion, and resolution of technical implementation issues, and
- For each market change, a detailed project release page containing business requirements specifications, user interface documentation, market simulation testing plans, release notes, and other artifacts.

An alternative model could concentrate these functions in a Change Working Group as described in the remainder of this Section 16.

The following protocol outlines the methods that govern MO System changes that directly impact members' processes, systems, or interfaces with MO systems. The intent of this protocol is to ensure there is transparency when member-impacting changes occur to MO processes and/or systems.

The MO CWG (Change Working Group) is the group responsible for monitoring and coordinating all planned member-impacting system or process changes that meet one or more of the following criteria:

- The change will result in members having to make changes to their internal systems or interfaces
- The change will require members to coordinate testing with MO prior to the change being released to Production systems
- The change will cause members to change their internal processes
- The change modifies or creates a system interface between MO and its members
- The risk associated with the change justifies inclusion as a member-impacting change

The CWG and MO will develop and maintain a plan outlining member-impacting change initiatives. This plan will be updated at least quarterly and posted to the CWG page on the MO Corporate Website. The plan will reflect the relative priority of all member-impacting change initiatives. These priorities will be determined based on the PRR ranking process conducted by the MO Market Working Group (MWG) as well as internal project prioritization processes in place at MO. System changes that cannot be implemented according to the requested priority will be identified and communicated to the MWG, after coordination with the CWG. The plan will include, at a minimum, the following:

- Listing and description of planned member-impacting projects

- Updated current status of planned member-impacting projects
- Identifiable milestones of planned member-impacting projects, including, but not limited to:
    - Requirements Signoff
    - Schedule of Testing and Training
    - Communication of Expectations / Specifications
    - Release of Required Documentation
    - System Release Dates

All member-impacting change initiatives are classified as minor, medium, major or emergency changes. The classification of these initiatives will be routinely reviewed and discussed by the Change Working Group and alternative timelines will be recommended, depending on the scope of the individual projects. MO will maintain a list of system changes and their associated classifications for discussion and coordination with the CWG.

- **Minor Change** – a change to an MO system that corrects or changes existing functionality but does not require members to make any changes to their systems, nor test the new functionality in a coordinated fashion with MO. An example of a minor member-impacting change would be an enhancement to member accessible web page that includes adding newly available options or functionality. For minor member-impacting changes, MO staff is required to notify the membership at least two (2) weeks prior to implementation in production.

- **Medium Change** - a change to an MO system that involves changes to system interfaces between MO and its members, such as changes to XML file specifications or Application Programmable Interfaces (API). The process for interface changes must allow sufficient time for members to assess the impact of the change to their systems, make appropriate revisions, and complete testing in an offline environment, where applicable. MO staff is required to notify the membership at least four (4) weeks prior to implementation in production, or as defined and agreed to by the CWG.

- **Major Change** - a change to an MO system that introduces a new member-facing application, major system functionality or wholesale process changes. These changes will always be managed by MO as projects, with milestones defined on the plan that is updated quarterly, and will include member participation, coordination, and testing throughout the project phases. For major changes that require the development of new applications or interfaces by members, MO staff is required to coordinate the project schedule by means of the Change Working Group to determine the appropriate lead times for documentation, testing, and implementation.

- **Emergency Change** – a member-impacting change to an MO system that is required to immediately restore or correct existing functionality. If changes to member systems or processes are required as a result of an Emergency Change, where appropriate, MO staff will:

  - Communicate the need for the change with MO members via an emergency conference call. The communication will include a discussion of impacts, risks, and timelines.

Root Cause Analysis

Within 30 calendar days of any unplanned system outage, in which Market Participants were instructed by MO to hold their deployment levels for a period of time, MO staff will perform a root cause analysis of the event and publish an executive summary of its findings to the CWG distribution list, and other applicable MO member distribution lists. Staff will provide bi-weekly updates (via e-mail) to the CWG on the progress associated with the root cause analysis. The analysis will outline the root cause of the event, describe remediation actions to prevent future reoccurrences, and specify if changes or workarounds that may have been put into place, will remain in production on a permanent or temporary basis.

Appendix

A – Registration Package

A variety of market participants are active in the WECC region, including generation owners, load serving entities, power marketers who buy / sell energy and/or represent generation owners in the wholesale market, metered subsystems (generally, municipal utilities and other governmental organizations), demand response aggregators, etc. The Market Operator provides registration materials, training programs, and customer service contacts that match parket participants to the materials that are appropriate for their roles in the market. The current electronic version of the registration-related materials ~~package~~ is available at the following link:

MO Registration Documents
http://www.caiso.com/participate/Pages/default.aspx

B – XML Specifications

Confidential information and data communicated between the Market Operator and its participants during the course of planning and market activities are protected through robust system and application security. Access requirements, application technical specifications, and user guides are available at the following link:

Application Access Documentation
http://www.caiso.com/participate/Pages/ApplicationAccess/Default.aspx

[Note: SPP-specific text has been deleted.]

C – Meter Technical Protocols

Submission of load, resource, and interconnection meter data is essential to the Market Operator's settlements, but it is expected that existing meter data in conformance with NERC, NAESB, and WECC standards and business practices, and existing balancing authority practices, may be adequate for EIM settlements. To the extent that Market Operator guidance on meter technical protocols is needed, these requirements are documented in the Business Practice Manual for Metering, which is available at:

Business Practice Manual for Metering
https://bpm.caiso.com/bpm/bpm/version/000000000000168

[Note: SPP-specific text has been deleted.]

D– Settlement Metering Data Management Protocols

The Business Practice Manual for Metering (listed above) covers the metering responsibilities for the MO, metered entities, and scheduling coordinators meter installation, certification and maintenance in addition to the creation of Settlement Quality Meter Data (SQMD) for billable quantities to represent the energy generated or consumed during a settlement interval. In order to execute the settlement calculation rules and processes, the Settlements system provides the mechanisms for the identification, control, scheduling, receipt, and validation of the various inputs, including, but not limited to, the Meter Data Acquisition System (MDAS) and the State Estimator. Details for the processing of meter data in the Settlements system are provided by the Business Practice Manual for Settlements and Billing, which is available at:

Business Practice Manual for Settlements and Billing
https://bpm.caiso.com/bpm/bpm/version/000000000000085

Details for meter data preparation by metered subsystems within the CAISO BAA (generally, municipal utilities and other governmental organizations, some of which maintain load following within their boundaries) are provided by the Business Practice Manual for Metering, listed above. Similar principles apply to Balancing Areas within the EIM market, and include MO certified revenue quality meters at each interface point affecting the market area and MO certified revenue quality meters on all generating units or, if aggregated, each individual resource.

[Note: SPP-specific text has been deleted.]
