Business Practice Manual for

Market Operations

Version ~~54~~55

Revised: ~~October, 2017~~February 13, 2018

Approval History

Approval Date: March 23, 2009

Effective Date: March 31, 2009

BPM Owner: David Delparte

BPM Owner's Title: Director of Operational Readiness

Revision History

Version	PRR	Date	Description
55	1036	02-13-2018	• Due to the extension of Aliso Canyon Tariff provisions. CAISO will extend the temporary measures beyond November 30th, 2017. • Created section 8.0 for E-Tagging that moved Post Market Activities to a new Section 9.0 • Updated section 7.2.2, 7.2.2.1 to reference section 8.0 • Additional miscellaneous updates to paragraphs 2.1.13, 7.2.3.4 & 7.8.2
54	1015	10-30-2017	As part of Market & Operational Excellence, the controllable devices (i.e. phase shifters) market setup and optimization features were added to the markets.
53	991	07-13-2017	PRR 991 Changes to reflect the new tariff requirements and new policy on Administrative pricing. Effective May 2, 2017
52	985	05-31-2017	PRR 985 The first change is to reduce the amount of power balance constraint relaxation for over-supply conditions. The other two changes are updates due to additional EIM entities; and deletion of penalty prices related to flexible ramp constraint which is no longer in place after the implementation of the flexible ramping product. Effective date for the power balance relaxation constraint is April 10th.

Version	PRR	Date	Description
51	953, 945	02-02-2017	PRR 953 Due to Aliso Canyon phase 2 gas-electric coordination initiative and the interim tariff revisions from December 1, 2016 through November 30, 2017. Effective date December 1, 2016 PRR 945 To improve the accuracy of market power mitigation for 5-minute real time dispatch market. Effective date is March 1, 2017. Miscellaneous corrections
50	921, 938	10-07-2016	PRR 921 Added changes for ESDER1 for NGR Enhancements for DA Starting SOC and NGR Option to not use Energy Limits or SOC in optimization. Sections 2.1.1.3, 2.1.13.1,4.6.1,6.6.2.3,7.1,7.8.2.5 PRR 938 additional edits due to the Flexible Ramping Product initiative. Effective date 11/1/2016
49	935	09-12-2016	PRR 935 changes related to the Pricing Enhancement policy
48	909, 917, 918, 887	09-01-2016	PRR 909 Adding Addendum due to Aliso Canyon gas-electric coordination initiative and the interim tariff revisions. PRR 917 improving the accuracy of RTM power mitigation procedure. PRR887 Transfer ULR information from Reliability Requirement BPM.
47	906	07-19-2016	PRR 906 Added new section 6.6.1.1.1 for MLC adjustment under Pmin re-rate
46	894	06-17-2016	PRR 894 Penalty price parameters adjustment due to ABC functionality. Also added correction to paragraphs 4.6.3 & 4.2.7
45	869	11-24-2015	PRR 869 Scheduling priority for transmission rights update. Section 5.1.9
44	847	07-06-2015	PRR 847 for clarification/adjustment on the penalty price values
43	754	02-19-2015	*This change was missed from the previous update PRR 754 Changes in support of RDRR initiative. Changes made to sections 2.1.2, 4.6, 7.1, and 7.11.1
42	778/805 806/810 811/813	12-11-2014	PRR 778 change SLIC to outage management system PRR 805 for Pay for Performance Enhancement PRR 806 for Nodal Group Limit Constraint changes PRR 810 Change CMRI to Customer Market Results Interface PRR 811 MSS elections & participation change PRR 813 Addition of flexible ramping constraint penalty price

Version	PRR	Date	Description
41	750/789	09-30-2014	PRR 750 for FNM expansion, PRR 760 for SC self-certification (section A13), and PRR 781 for FERC order 789
40	733/738	05-01-2014	PRRs 733 & 738 Penalty price changes
40	736	05-01-2014	PRR 736 Updating content to provide additional clarity and to reflect lessons learned since original implementation of Attachment G.
40	747	07-09-2014	PRR 747 This change to the penalty price for over-procurement in RUC is to allow RUC to relax the power balance when RUC procurement is higher than the Demand forecast
39	732/764	05-06-2014	PRR 732 was added as an emergency for the purpose of order 764, changes were made to section 7.10.4
39	734/735	05-06-2014	PRRs 734 & 735, changes made to attachments A,B,E,F,H,I
39	716/733	05-06-2014	PRR 716, corrections were initially made, then PRR 733 was created on an emergency basis for further clarification, corrections made to section 6.6.5
39	704	05-06-2014	PRR 704 FERC order 764
39	702	05-06-2014	PRR 702 Price correction changes
38	695	01-6-2014	PRR 695-Corrections Clarifications 2013. Changes made to sections 2.5.2.1 and 6.1.7.
38	696	01-6-2014	PRR 696-Minimum Online Commitment Constraint. New section 6.6.2.4 added.
37	684	10-02-2013	PRR 684 - Change multi-stage generator (MSG) transition rounding method in Day-Ahead market. Changes made to section 4.5.
36	663	07-03-2013	PRR 663 - Modify transmission constraint relaxation parameter. Changes made to section 6.6.5.
36	673	07-03-2013	PRR 673 - Pay for performance regulation – clarifications. Changes made to sections 4.3.1, 4.6.1, and Appendix Attachment J section J.3.
35	657	06-04-2013	PRR 657 - pay for performance regulation. Changes made to sections 2.5.2, 4.1.1, 4.2.1, 4.2.6, 4.3.1, 4.3.2.1, 4.4, 4.6.1, 6.1.4, 6.6.1.1, 7.2.3, 7.2.3.2 and 7.6.4. New Appendix Attachment J added.

Version	PRR	Date	Description
34	651	05-03-2013	PRR 651 - Local market power mitigation implementation phase 2. Changes made to sections 2.3.1.1, 2.3.2.1, 6.5.3, 6.7.2.7, 6.7.4.2, 7.4, 7.5.4, 8.1.2, and Appendix Attachment B sections B.1 and B.2. New section 7.4.1 added.
34	652	05-03-2013	PRR 652 - Multi-stage generation enhancements phase 3. Changes made to section 2.1.5, 7.6.3.3 and Appendix Attachment D sections D.7.4 and D.7.5.
34	653	05-03-2013	PRR 653 - Price inconsistency market enhancements. Change made to section 3.1.5.
34	655	05-03-2013	PRR 655 - Treatment of Market Participants with Suspended Market-Based Rate Authority. Change made to section 6.7.2.7.
33	644	04-05-2013	PRR 644 - Marginal Cost of Losses - Inside CAISO Grid But Outside CAISO BA. New Appendix Attachment I added.
32	639	03-12-2013	PRR 639 - Circular Scheduling. Changes made to Appendix Attachment F. New section F.4 added. New Appendix Attachment H added.
31	630	02-11-2013	PRR 630 - Electronic communication of ELC instructions from RUC. Change made to section 6.8.
31	632	02-11-2013	PRR 632 - Conform setting feasibility adjustment. Change made to section 7.5.2.
31	635	02-11-2013	PRR 635 - RTUC advisory solution and clarification to market disruption. Changes made to sections 7.6.4, 7.8.3, 7.10.4, 7.10.4.1 and 7.10.4.2.
30	611	01-09-2013	PRR 611 - Real-time market parameter change. Change made to section 6.6.5.
29	597	12-10-2012	PRR 597 – Changes to support flexible ramping settlement. Change made to section 7.1.3. New section 7.1.3.1 added.

Version	PRR	Date	Description
28	559	11-12-2012	PRR 559 - Update Market Power Mitigation process description in BPM. Changes made to sections 6.5.3.1, 6.6.5, and Appendix Attachment B, sections B.2.1.1 and B.2.2.
28	560	11-12-2012	PRR 560 - Changes to support grouping constraints initiative - part II a. Change made to section 2.1.6.1.
28	561	11-12-2012	PRR 561 - Revise description of real-time load forecast software. Change made to section 7.8.1.3.
28	563	11-12-2012	PRR 563 - Changes to Expected Energy algorithm to incorporate non-generator resources. Changes made to Appendix attachment C, sections C.1, and C.2.
28	568	11-12-2012	PRR 568 - Changes to consideration of minimum load costs and initial conditions. Changes made to sections 6.1.9, 6.6, 7.1, and 7.3.1.3.
28	571	11-12-2012	PRR 571 - Contingency dispatch enhancements part 1. Change made to section 7.9.
28	575	11-12-2012	PRR 575 - Modify system power balance constraint parameter. Change made to section 6.6.5.
28	584	11-12-2012	PRR 584 - Contingency dispatch enhancements part 2. Changes made to sections 7.9 and 7.9.3.
28	586	11-12-2012	PRR 586 - Changes to support non-generator resources and regulation energy management. Changes made to sections 4.6.1, 6.5, 6.6.2, 7.1, 7.5.1 and 7.6.3.1. New sections 2.1.13, 2.1.13.1, 6.6.2.3 and 7.8.2.6 added.
27	550	06-06-2012	PRR 550 - Changes to support Transmission Reliability Margin functionality. Changes made to sections 2.3.1, 2.5.2.4.1, 4.2, 5.1.5, 5.1.7, 5.1.9, 5.1.11, 5.2.1, 5.2.2, 5.2.3, 6.1.6, 6.1.7, 6.4.2, 6.4.4, and 7.1
26	546	05-07-2012	PRR 546 - Remove RDRR language from BPM for Market Operations. Changes made to sections 2.1.2, 4.6, 6.7.2.7, 7.1, and 7.11.1

Version	PRR	Date	Description
25	532	04-09-2012	PRR 532 - Changes to support local market power mitigation enhancements. Changes made to sections 2.3.1, 2.3.1.1, 2.3.1.2, 2.3.2.1, 2.3.2.2, 2.4.5, 6, 6.2, 6.3.1, 6.4.5, 6.4.6, 6.5, 6.5.1, 6.5.2, 6.5.3, 6.5.5, 6.6, 6.6.5, 6.7.2.6, 6.7.2.8.1, 7.2.1, 7.3.3, 7.4, 7.9, Appendix Attachment B, sections B and B.1 through B.12, Appendix Attachment C section C.2.1.1.25, and Appendix Attachment D sections D.3.1 and D.6.1. New sections 6.5.3.1 and 6.5.3.2 added.
25	535	04-09-2012	PRR 535 - Changes to support Multi-stage generation enhancements functionality. Changes made to sections 2.1.5 and 6.6.2.
24	523	03-08-2012	PRR 523 - MSG Enhancement Dec 2011. Change made to section 7.6.3.3.
24	526	03-08-2012	PRR 526 - Miscellaneous PIRP related changes. Changes made to Appendix Attachment A, sections A.13.6.1 and A.13.6.5.
23	495	12-09-2011	PRR 495 - Changes in support of Flexible Ramping Constraint initiative. New section 7.1.3 added.
22	479	10-28-2011	PRR 479 - Changes to support the 72 hour RUC initiative. Changes made to section 2.3, 2.3.1.3, 2.3.1.4, 6.4.7, 6.7 and subsections, 6.8, and 7.7.
22	482	10-28-2011	PRR 482 - Changes to support grouping constraints initiative. Change made to section 2.1.6.1. New section 6.6.2.2 was added.
22	483	10-28-2011	PRR 483 - Changes to support interim dynamic transfer functionality. New section 7.8.2.5 was added.
22	485	10-28-2011	PRR 485 - Clarify telemetry requirements for Eligible Intermittent Resources. Changes made to appendix Attachment A, sections A.13.2.2 and A.13.3.3.
21	454	09-19-2011	PRR 454 - Changes in support of RDRR initiative. Tariff effective 4/1/12. Changes made to sections 2.1.2, 4.6, 6.5.1, 6.7.2.6, 7.1, and 7.11.1

Version	PRR	Date	Description
20	443	08-12-2011	PRR 443 - Market Ops companion changes to support new Direct Telemetry BPM. Changes made to appendix attachment A, section A.13.
20	445	08-12-2011	PRR 445 - Virtual Bidding -- Interties With Zero ATC. Changes made to section 2.5.2.4.1 and 6.4.4
19	426	06-13-2011	PRR 426 - Forbidden Operating Region Compliance Feature. Changes made to section 7.2.3.7
18	385	05-18-2011	PRR 385 - Open/isolated intertie handling companion language for Market Operations BPM. Detail provided in Market Instruments BPM. Changes made to sections 6.4.4 and 7.1
18	420	05-18-2011	PRR 420 - Cleanup of sections 2.4.2.2 and 6.1.2. These sections changed to reflect most recent information.
17	360	04-01-2011	PRR 360 - Market Ops - Clarification of Power Balance Constraint Parameters. Entry added to Real Time Market Parameters table in section 6.6.5.
17	375	04-01-2011	PRR 375 - RUC Availability bids for RA resources - conform Market Ops language to Market Instruments. Changes were made to section 6.7.2.6
17	378	04-01-2011	PRR 378 - Change market parameter value for Ancillary Service Maximum Limit. An entry was changed in both the Integrated Forward Market (IFM) Parameter Values table and the Real Time Market Parameters table in section 6.6.5.
17	421	04-01-2011	PRR 421 - Change market parameter values to reflect increased bid cap. Multiple entries were changed in both the Integrated Forward Market (IFM) Parameter Values table and the Real Time Market Parameters table in section 6.6.5.

Version	PRR	Date	Description
16	342	01-26-2011	PRR 342 - Market Operations BPM changes in support of convergence bidding. Changes were made to sections 2.1.2, 2.2.1, 2.2.3, 2.2.4, 2.3.1, 2.3.1.1-2.3.1.3, 2.3.2, 2.4.5, 2.5.2, 3.1, 3.1.4, 3.2.4, 6.1.3, 6.1.8, 6.3.1, 6.4.4, 6.4.6, 6.5.1, 6.6, 6.6.1.1, 6.6.3, 6.6.6, 6.6.7, 7.1, 8.1.5.4 and appendix Attachments D and E. New sections 2.5.2.4, 3.1.10, 6.6.5.4, and appendix Attachment F were added.
15	349	12-21-2010	PRR 349 - Changes for Market Ops BPM in support of revised Scarcity Pricing Proposal. Changes were made to section 4.2. New section 4.4.1 was added.
15	354	12-21-2010	PRR 354 - Implementation of Market Issues process in support of Post Five-Day Price Correction Process. New appendix Attachment G was added.
15	355	12-21-2010	PRR 355 - Initial Condition for Day-Ahead Market Resources. New section 6.1.9 was added.
15	358	12-21-2010	PRR 358 - Clarification of use of minimum effectiveness threshold. Changes were made to section 3.2.4.
14	345/359	12-07-2010	PRR 345 and 359 – Changes related to the Multi-Stage Generating Resource modeling implementation. Changes were made to sections 2.2.1, 2.4.5, 2.5.2, 4.3, 4.3.2, 4.5, 4.6, 6.5.1, 6.6, 6.6.1.2, 6.6.2, 6.6.2.1, 7.2.3.1, 7.2.3.6, 7.3.1.3, 7.5.3.2, 7.6, 7.6.3.1, 7.8.2.2, 7.11, 7.11.1 and appendix Attachments C and D. New sections 2.1.5, 7.6.3.3, 7.6.3.4, and 7.6.3.5 were added.
13	296	10-01-2010	PRR 296 – LDF adjustment due to weather. Changes were made to section 3.1.4
13	297	10-01-2010	PRR 297 – Post five-day price correction process. Changes were made to section 8.
13	301	10-01-2010	PRR 301 – Clarification of MSS election options. New section 2.4.2.3 was added.
12	281	09-14-2010	PRR 281 – Wheeling out and wheeling through transactions. Changes were made to section 2.5.2.2

Version	PRR	Date	Description
11	167	08-09-2010	PRR # 167 - Market Operations BPM changes related to PDR. Changes were made to sections 2.1.2, 2.4.4, 2.4.5, 2.5.2.1, 2.5.2.3, 4.1.1, 4.2.1, 4.6, 4.6.3, 6.5.1, 7.4, 7.8.1.2
10	276	7-26-2010	PRR # 276 - Detail related to Eligible Intermittent Resources (EIRs). Changes were made to Appendix A sections 13, 13.2, 13.2.2, 13.3, 13.3.1, 13.3.2, 13.3.3, 13.3.5, 13.5, 13.7; New section 13.4 was added.
9	215	6-15-2010	PRR # 215 - Details related to the Forbidden Operating Region (FOR) implementation. Changes were made to sections 7.8.2.4, 7.10.4 and 7.10.4.1.
8	213	6-1-2010	PRR # 213 - Price Corrections Make Whole Payments. A new appendix E was added.
7	132	5-12-2010	PRR # 132 - Market Operations BPM Updates related to PIRP
7	202	5-12-2010	PRR # 202 - Update hyperlink to market data
6	170	4-15-2010	PRR # 170 - Market Operations BPM changes related to RTM forbidden operating region (FOR) implementation.
5	189	4-1-2010	PRR # 189 - Five-Day Price Correction Time Horizon. Changes were made to section 8.1.6.2 of the BPM.
5	201	4-1-2010	PRR # 201 - Proposed parameter changes for April 1, 2010 Energy Bid Cap increase to $750. Changes were made to sections 2.2.2 and 6.6.5 of the BPM.
5	171	4-1-2010	PRR # 171 - Market Operations BPM changes related to AS in HASP. The following sections were updated :2.3.2, 2.3.2.1 , 2.3.2.2, 2.3.2.3, 4.3.2, 4.5, 7.2.2, 7.2.3.2, 7.3.3, 7.3.4, 7.5, 7.5.4, 7.5.5, 7.5.5.2, 7.6.2. The following new sections were added: 7.6.2.1, 7.9.4.1
4	86	12-31-2009	PRR # 86 – Changes to Market Operations BPM arising out of implementation of Standard Capacity Product. Changes were made to Section 6.6.3 due to

Version	PRR	Date	Description
			implementation of Standard Capacity Product initiative.
4	100	12-31-2009	PRR # 100 - Market Operations BPM changes due to Simplified ramping rules implementation. Changes were made to Section 6.6.2 and Section 7.6.3.2 of the BPM.
4	104	12-31-2009	PRR # 104 - Revisions to ensure consistency with RMR contract and tariff requirements. Changes were made to Section 6.5.1 and Section 6.5.2 of BPM.
3	78	11-02-2009	PRR # 78 – New Expected Energy Calculation Schedule effective with Payment Acceleration. Changes were made to Appendix C Section C.6 due to implementation of payment acceleration initiative.
2	39	10-14-2009	PRR # 39 – Changes were made to Appendix C Section C.4.1 to reflect new expected energy types arising from implementation of new exceptional dispatch codes.
1		3-23-2009	Version Release

TABLE OF CONTENTS

Attachments:

Attachment A: Market Interfaces

Attachment B: Competitive Path Assessment

Attachment C: Expected Energy Calculation

Attachment D: Commitment Cost Determination

Attachment E: Price Corrections Make Whole Payments

Attachment F: CRR Settlement Rule

Attachment G: Process for Addressing Market Issues

Attachment H: Circular Schedule

Attachment I: Implementation of Marginal Cost of Losses and Transmission Losses for Facilities on the CAISO Controlled Grid outside the CAISO Balancing Authority Area

Attachment J: Calculation of Weekly Mileage Multipliers

List of Exhibits:

1.   Introduction

Welcome to the CAISO *BPM for Market Operations*. In this Introduction you will find the following information:

> ➢ The purpose of CAISO BPMs

> ➢ What you can expect from this CAISO BPM

> ➢ Other CAISO BPMs or documents that provide related or additional information

1.1   Purpose of CAISO Business Practice Manuals

The Business Practice Manuals (BPMs) developed by CAISO are intended to contain implementation detail, consistent with and supported by the CAISO Tariff, including: instructions, rules, procedures, examples, and guidelines for the administration, operation, planning, and accounting requirements of CAISO and the markets. Each Business Practice Manual is posted in the BPM Library at: http://bpmcm.caiso.com/Pages/BPMLibrary.aspx. Updates to all BPMs are managed in accordance with the change management procedures included in the **BPM for Change Management**.

1.2   Purpose of this Business Practice Manual

This *BPM for Market Operations* covers the rules, design, and operational elements of the CAISO Markets. The BPM is intended for those entities that expect to participate in the CAISO Markets, as well as those entities that expect to exchange Power with the CAISO Balancing Authority Area.

This BPM benefits readers who want answers to the following questions:

> ➢ What are the roles of CAISO and the Scheduling Coordinators in the CAISO Markets?

> ➢ What are the concepts that an entity needs to understand to engage in the CAISO Markets?

> ➢ What does a Market Participant need to do to participate in the CAISO Markets?

> ➢ What are the market objectives, inputs, and outcomes?

Although this BPM is primarily concerned with market operations, there is some overlap with other BPMs. Where appropriate, the reader is directed to the other BPMs for additional information.

If a Market Participant detects an inconsistency between BPMs, it should report the inconsistency to CAISO before relying on either provision.

The provisions of this BPM are intended to be consistent with the CAISO Tariff. If the provisions of this BPM nevertheless conflict with the CAISO Tariff, the CAISO is bound to operate in accordance with the CAISO Tariff. Any provision of the CAISO Tariff that may have been summarized or repeated in this BPM is only to aid understanding. Even though every effort will be made by the CAISO to update the information contained in this BPM and to notify Market Participants of changes, it is the responsibility of each Market Participant to ensure that he or she is using the most recent version of this BPM and to comply with all applicable provisions of the CAISO Tariff.

A reference in this BPM to the CAISO Tariff, a given agreement, any other BPM or instrument, is intended to refer to the CAISO Tariff, that agreement, BPM or instrument as modified, amended, supplemented or restated.

The captions and headings in this BPM are intended solely to facilitate reference and not to have any bearing on the meaning of any of the terms and conditions of this BPM.

1.3   References

The definition of acronyms and words beginning with capitalized letters are given in the *BPM for Definitions & Acronyms*.

Other reference information related to this BPM includes:

➢ Other CAISO BPMs
➢ CAISO Tariff

2.   Market Operations Overview

Welcome to the *Market Operations Overview* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

➢ A high-level description of the structure and operations of the CAISO Markets

Subsequent sections "drill down" in greater detail. Included in subsequent sections are the following topics:

➢ Market activities which consist of:
- The buying and selling, transmission of Energy or Ancillary Services into, out of, or Wheeling Through the CAISO Balancing Authority; and the allocation of transmission
- The request or receipt of Congestion Revenue Rights through allocations or auctions

➢ Products and services that are traded in the CAISO Markets

➢ CAISO Markets which consist of:
- Day-Ahead Market, which includes the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC)

  Real-Time Market processes, which includes the following processes: (1) the Hour-Ahead Scheduling Process, (2) Real-Time Unit Commitment (RTUC), (3) the Short-Term Unit Commitment (STUC), (4) the Fifteen Minute Market (FMM), and (5) the Real-Time Dispatch (RTD).
- Objectives, inputs, and outputs

➢ Roles and responsibilities according to market activities

➢ Market Information, which consists of resource static data, Bids, Inter-SC Trades

2.1   Market Entities

The entities that engage in the operation of the CAISO Markets are described in the following subsections.

2.1.1   CAISO

CAISO is a non-profit public benefit corporation that:

➢ Has Operational Control of transmission facilities of all Participating Transmission Owners

➢ Is the Balancing Authority Area Operator for the CAISO Balancing Authority

➢ Administers the CAISO Markets

2.1.2   Scheduling Coordinators

It is important to note that all business with the CAISO Markets, except for acquisition and holding of Congestion Revenue Rights (CRRs), must be conducted through CAISO-approved and registered entities called Scheduling Coordinators (SCs). The primary responsibilities of SCs include as applicable:

➢ Represent Generators, Load-Serving Entities, Proxy Demand Resources (PDR), Reliability Demand Response Resources (RDRR), importers, and exporters
➢ Provide NERC tagging data
➢ Submit Bids[1] and Inter-SC Trades
➢ Settle all services and Inter-SC Trades related to the CAISO Markets
➢ Ensure compliance with the CAISO Tariff
➢ Submit annual, weekly, and daily forecasts of Demand

2.1.3   Participating Generators

A Participating Generator is a Generator that is able to sell and provide Energy or Ancillary Services through an SC over the CAISO Controlled Grid from a Generating Unit with a rated capacity of 1 MW or greater, or from a Generating Unit providing Ancillary Services and/or submitting Energy Bids through an aggregation arrangement approved by CAISO, that has undertaken to be bound by the terms of the CAISO Tariff, in the case of a Generator through a Participating Generator Agreement.

A Participating Generator must register with an SC who acts on the Participating Generator's behalf for the sale of Energy or Ancillary Services into the CAISO Markets. All CAISO Markets transactions engaged in by the SC for specific Participating Generators is settled with the applicable SC.

2.1.4   Constrained Output Generator

A Constrained Output Generator (COG) is a Generating Unit with a zero or very small operating range between its Minimum Load (Pmin) and Maximum Capacity (Pmax).

---

[1] Including Virtual Bids

Generating Units are eligible to elect COG status, on an annual basis, and benefit from the flexible COG model only if their actual operating range (Pmax – Pmin) is not greater than the highest of three (3) MW or five percent (5%) of their actual Pmax. Eligible Generating Units that elect COG status must make an election before each calendar year. Resources with that have zero operating range must participate as COGs. Resources with a non-zero operating range have the option to participate as a COG. The election is made by registering the resource in the Master File as having a PMin equal to PMax less 0.01 MW (PMin+ PMax -0101 MW) within the time frame for submitting Master File changes so that the change becomes effective by the first of the year. . COGs must also elect the Proxy Cost or Registered Cost option for Start Up and Minimum Load cost, similar to all other Generating Resources. Registered COGs may submit an Energy Bid to indicate participation in the market for the relevant Trading Hour.   The submitted Energy Bid will be replaced by the CAISO with a Calculated Energy Bid determined by dividing its Minimum Load Cost by MW quantity of the resources PMax. COG may not bid or self-provide Regulation or Spinning Reserve, but they may be certified for Non-Spinning Reserve provision if they are Fast Start Units. Registered COGs may also self-schedule at their Pmax. COGs are not eligible to submit RUC bids or received compensation for any RUC Awards.

2.1.5   Multi-Stage Generating Resources

Generating Units and Dynamic Resource-Specific Resources may register and qualify as Multi-Stage Generating Resources pursuant to the requirements specified in Section 27.8 of the CAISO Tariff. Multi-Stage Generating Resources are Generating Unit or Dynamic Resource-Specific System Resource that for reasons related to its technical characteristics can be operated in various MSG Configurations such that only one such MSG Configuration can be operated in any given Dispatch Interval. Subject to the requirements in Section 27.8 of the CAISO Tariff, the following technical characteristics qualify a Generating Unit or Dynamic Resource-Specific System Resource as a Multi-Stage Generating Resource if the resource; (1) is a combined cycle gas turbine resource; (2) is a Generating Unit or Dynamic Resource-Specific System Resources with multiple operating or regulating ranges but which can operate in only one of these ranges at any given time; or (3) has one or more Forbidden Operating Regions. Metered Subsystems, Pumped-Storage Hydro Units, and Pumping Loads, and System Resources that are not Dynamic Resource-Specific System Resources do not qualify as Multi-Stage Generating Resources.

This modeling approach allows for a specified number of discrete states (one Off state and at least two On states with different resource configurations). Each on-line state represents a MSG

Configuration in which the Multi-Stage Generating Resource can operate. Operating limits and technical characteristics are defined for each MSG Configuration separately and are retained in the Master File. Each MSG Configuration is modeled as a logical generator with its own individual components such as operating limits, ramp rate, Minimum Load Cost, Transition Costs, and Energy Bids.

The Transition Matrix contained in the Master File includes a prescribed set of feasible MSG Transitions that indicate the feasible transition from one MSG Configuration to another. Transition Costs and Transition Times, defined in the registered Transition Matrix can be different for each defined transition. Transitions that are not registered in the Transition Matrix are not considered by the CAISO Market processes. Each of the MSG Configurations have specified minimum on-state time, minimum off-state time.

The following are some of the characteristics of Multi-Stage Generating Resources:

➢ The Economic Bids and Self-Schedules are defined at the MSG Configuration level.

➢ The outage information from outage management system is obtained at the MSG Configuration and the Generating Unit level (i.e. plant level). The market applications use PMax derate or PMin uprate information from outage management system at the MSG Configuration level for most processes; however it uses outage information at the overall plant level for validating Exceptional Dispatch instructions.

➢ The Scheduling Coordinator may register up to six MSG Configurations without any limitation on the number of transitions between the registered MSG Configurations in the Transition Matrix.   If the Scheduling Coordinator registers seven or more MSG Configurations, then the Scheduling Coordinator may only include two eligible transitions between MSG Configurations for upward and downward transitions, respectively, starting from the initial MSG Configuration in the Transition Matrix.

➢ In addition, no Forbidden Operating Region (FOR) is allowed in any MSG Configuration, and Operational Ramp Rate curves are limited to two segments within a given MSG Configuration. Consequently, the ramp-rate de-rate from outage management system will be limited to two segments for a given MSG configuration accordingly.

➢ Separate Minimum Up Time (MUT) and Minimum Down Time (MDT) constraints can be enforced at both the plant and individual MSG Configuration levels. In addition, MUT and MDT constraints may be specified for a group of MSG Configurations. Specific features are as follows:

➢ Plant level: MUT includes the Transition Times of all the MSG Configurations being switched.

➢ Group level:

➢ MUT represents the total time that the Multi-Stage Generating Resource must stay within the group. For example, suppose a Multi-Stage Generating Resource has 6 configurations, with configurations 5 and 6 part of a group with a MUT of 6 hours. Once dispatched into either configurations 5 or 6, the resource may transit freely between configuration 5 and 6, but cannot move to a different configuration until the 6 hour MUT has passed. Transition time between MSG configurations within the group is considered as "ON" Time of the group.

➢ MDT represents the total time that the Multi-Stage Generating Resource must stay outside of the group. When considering the MDT of a group, the time that the Multi-Stage Generating Resource is operating in a configuration outside the group or within transition outside of the group is considered as the "OFF" time period for the group, in addition to the time that the resource is off line.

➢ Configuration level: When considering the MDT of a given MSG Configuration, the time that the Multi-Stage Generating Resource is operating on a different configuration or transitioning is considered as the "OFF" time period for the given MSG Configuration, in addition to the time that the resource is off line.

2.1.6   Participating Loads

A Participating Load is an entity providing Curtailable Demand, that has undertaken in writing (by executing a Participating Load Agreement between CAISO and such entity) to comply with all applicable provisions of the CAISO Tariff, as they may be amended from time to time.

From the electrical point-of-view, curtailing Participating Load is analogous to increasing electricity Supply or Generation. Most Participating Loads are Pumping Loads.

Curtailable Demand is Demand from a Participating Load that can be curtailed at the direction of CAISO in the Real-Time Dispatch of the CAISO Controlled Grid. SCs with Curtailable Demand may offer their product to CAISO to meet Non-Spinning Reserve or Imbalance Energy.

There are at least three types of Participating Load: 1) Pumping Load that is associated with a Pump-Storage resource, 2) A single Participating Load (i.e. Pumping and non-Pump Load) that

is not associated with a Pump-Storage resource; and 3) Aggregated Participating Load (i.e. aggregated Pumping and non-Pumping Load that is an aggregation of individual loads that operationally must be operating in coordination with each other.

The table below illustrates which of these models are used to accommodate the various types of Participating resources:

Participating Resources	Model Used	Comments
Pump-Storage Resources (i.e. Helms, San Luis)	Pump-Storage Hydro Unit Model	Model can support generation and pump mode. Pump mode is effectively negative generation mode.
Single Participating Load (single Pump and non-Pump Load)	Pump-Storage Hydro Unit Model.	For load (pump-only) the Generation capability of the Pump-Storage model is set to 0 MW. Therefore pump can use negative generation.
Aggregated Participating Load (i.e., aggregated Pumping and non-Pumping Load)	Extended Non-Participating Load Model	Energy will be bid and scheduled using Non-Participating Load in the Day-Ahead Market. To the extent resource is certified to provide Non-Spin, a pseudo-generator model will be used to offer Non-Spin and to the extent necessary dispatch energy from Non-Spin Capacity representing dropping pump load.

CAISO only accepts Bids for a Participating Load from an SC. If the SC is not the entity that operates the Participating Load itself, the SC submits Bids on behalf of the Participating Load for the Supply of Energy or Ancillary Services into the CAISO Markets. All CAISO Markets transactions engaged in by the SC, for a specific Participating Load, are settled with the applicable SC.

Below the following three categories of Participating Load that can participate in CAISO Markets are described further:

➢ Pumped-Storage Hydro Units

➢ Single Participating Load (i.e., Pumping load or non-Pumping Load)

➢ Aggregate Participating Load (i.e. aggregated Pump Load or non-Pumping Load

2.1.6.1   Pumped-Storage Hydro Unit Model

Under this model, the resource looks like a Generating Unit on one side and looks like Load (On or off – single segment) on the other. There are thus three distinct operating modes for a Pumped-Storage Hydro Unit (PSHU) that uses the full functionality of the model. These operating modes are:

➢ Pumping (i.e., pump on and consuming Energy)

➢ Offline (i.e., both generation and pump off and not producing or consuming Energy)

➢ Generating Energy like an ordinary Generating Unit

It is not necessary to utilize all three modes. Some pumps are just pumps in that they only consume Energy, and do not generate Energy. If these pumps wish to participate and sell Imbalance Energy or Non-Spinning Reserves then they must use the same model as the Pumped-Storage Hydro Unit for submission of their Bids into the CAISO Market, but need not enter the Generation side of the model for the optimization. The Generator Bid data of the PSHU model can be left blank. Thus whether a facility is a PSHU or merely a pumping facility the same model is used in the optimization, but with differing levels of Bid data required depending on the functionality being supported.

PSHU can perform either as Generating Unit by supplying Energy or as Loads by consuming Energy from the grid, and therefore they are modeled in the CAISO Markets as Generating Units whose output can go negative when they are functioning as pumps. The PSHU model for Participating Loads models the pumps as Generating Unit with negative Generation capabilities and therefore schedules and settles them at nodal LMPs.

Pumps are modeled with a two-part Bid, namely Shut-Down Costs and Pumping Costs.

1) A Shut Down Cost is an event driven non-Energy based cost that is similar to Start-Up Costs associated with a Generating Unit. The Shut Down Costs represent the costs associated with action of shutting down the pump in dollars per shut-down event. This information is bid in. If the SC does not include any Shut Down Cost component, then the Scheduling Interface and Bidding Rules application (SIBR) inserts a pump Shut Down Cost of $0.

2) Pumping Cost is the hourly cost of operating a hydro pump and it occurs while the pump remains online. In each Trading Day, Pumping Costs are submitted separately for the IFM and the RTM, and may vary by each Trading Hour. Pumping Cost applies only to PSHU and hydro pumps.

3) Pumping Costs are similar in nature to Minimum Load Costs because they are single segment and are represented as a single price for a given Trading Hour for the quantity (MW) of Energy associated with the cost of operating the unit in pumping mode. The pumping operation is restricted to a single operating point, the pumping level, which is submitted with the Bid and can be different in each Trading Hour and across the CAISO Markets. The Pumping Cost is used in the DAM/RTM to optimally schedule the unit in pumping mode. The Pumping Cost represents different things depending on the following:

   a) If the facility is bidding to pump in either DAM or RTM then it represents the Energy Bid Costs the pump is willing to pay in either market, assuming the pump is not already scheduled to consume Energy in that market.

   b) In RTM if the facility has a pumping schedule then the Pumping Costs represent the price at which the pump is willing to be paid to curtail in RTM.

A PSHU facility may submit a Pump Shut Down Cost. If none is submitted, the CAISO will generate these values based on the Master File information. (See BPM for Market Instruments) No shut-down ramp rate is required as it is assumed to be infinite. The PSHU model does not handle Ramp Rates in pumping mode, i.e., the pump starts up / shuts down immediately.

Inter-temporal constraints in pumping mode consist of (1) minimum pumping time (separate from minimum generating time), (2) the maximum pumping Energy per Trading Day, (3) the maximum number of pumping cycles in a Trading Day, (4) minimum lag time between consecutive pump starts in a group[2], and (5) minimum down time. The CAISO minimum down

---

[2] See section 6.6.2.2 for more information on grouping constraints.

time model will allow for the specification of separate minimum down time values for each of four potential switching sequences:

➢ Minimum down time when switching from pumping to off to pumping (MDTpp)

➢ Minimum down time when switching from pumping to off to generation (MDTpg)

➢ Minimum down time when switching from generation to off to pumping (MDTgp)

➢ Minimum down time when switching from generation to off to generation (MDTgg) (essentially the existing minimum down time feature for generating resources)

In addition, if the PSHU is defined as a group, the following optional features are available:

➢ A unison operation feature will prevent simultaneous operation of resources in different modes. If selected, the feature will prevent PS resources within a group of resources from being committed in generation mode if any unit within the group is in pumping mode, or vice versa.

➢ A minimum lag feature specifies the minimum period between the time when the last PS resource in a group is shutdown in pumping mode and the first resource is started in generating mode and vice versa.

An additional feature pertains solely to the PSHU model. In most cases SCs may not submit Demand Bids in RTM because RTM clears Supply against the CAISO Forecast of CAISO Demand. Participating Load using the PSHU model is an exception to this rule in that it can submit Self-Schedules of Demand for Energy in RTM using the same PSHU model method discussed above. The PSHU model does not support aggregation of Participating Load. Rather, to the extent Participating Load makes use of the PSHU model it must represent a single load with a single telemetry and metering scheme.

2.1.6.2   Single Participating Load (Pumping and non-Pumping Load)

Although pumps are bid-in to consume Energy when they are pumping, pumps are modeled as negative Generation in DAM. In DAM an SC may either bid to procure Energy to pump using its Pumping Costs as a substitute of an Energy Bid, or it may Self-Schedule Energy to pump. Each pump is modeled individually. The SC may not submit an Economic Bid to Supply Energy because the generating mode of the PSHU model is not available for a single Participating Load. Furthermore, an SC may not bid to curtail a pump in DAM because in DAM a pump may only have a Pumping Cost or a Self-Schedule to consume Energy. An SC may offer Non-Spinning Reserve capacity in DAM from a pump, but such capacity is only awarded if the pump

is scheduled to consume Energy in the DAM. In RTM if an SC wishes to bid to curtail a pump to provide either Energy or Non-Spinning Reserves then it must have a non-zero pumping Schedule from DAM results. If the SC wishes to bid to pump (consume Energy) in RTM it must likewise have a zero pumping Schedule from DAM or a higher pumping level in RTM compared to their pumping schedule in the DAM.

The nature of an SC's schedule as the SC enters a market constrains the options available to facilities. If the SC has a zero pumping Schedule from DAM then obviously it cannot be curtailed to provide Energy in RTM as there is nothing to curtail. If the SC submits a pumping Self-Schedule or pumping ETC Self-Schedule, the resource will stay in pumping mode and will not be curtailed. Pumping Self-Schedule like any other Self-Schedule is a commitment to be on at minimum load and is effectively fixed. As a result, there is no economic signal available to de-commit the pump. Otherwise the resource will be scheduled optimally to pump or shutdown the pump based on its Pumping Cost and Pump Shut Down Cost.

Pumps can provide two products to the RTM, namely Imbalance Energy and Non-Spinning Reserves, if they enter that market with a non-zero pump Schedule from DAM.

2.1.6.3   Aggregated Participating Load (i.e. Pump and non-Pumping Load)

An Aggregated Participating Load will be modeled and will participate only in the CAISO's DAM as both a Non-Participating Load (NPL) for energy and as a pseudo generating unit for Non-Spinning Reserve through the Extended Non-Participating Load Model.   In the first release of MRTU, the Aggregated Participating Load will not be able to participate in the CAISO's markets using a Participating Load model.   Rather the Scheduling Coordinator on behalf of the Aggregated Participating Load may submit two Bids for the same Trading Day: (1) using a Non-Participating Load, model a Day-Ahead Self-Schedule with an Energy Bid Curve with a maximum 10 segments; and (2) as a Generator representing the demand reduction capacity of the Aggregated Participating Load, a submission to Self-Provide Non-Spinning Reserve or a Bid to provide Non-Spinning Reserve.   The CAISO will assign two Resource IDs: one for Non-Participating Load Bids and one for Generator Bids. Both Resource IDs will be in the Master File on behalf of the Aggregated Participating Load. The Aggregated Participating Load will be treated as a Participating Load for settlement and compliance purposes. As a result the Aggregated Participating Load will be settled at an Aggregate Pricing Node that represents the prices only of those PNodes that make up the Aggregate Participating Load.

2.1.6.4   Non-Pumping Facilities

While most Participating Loads are Pump Loads, There are two ways in which non-pumping Participating Load Resource[3] can participate in the CAISO Markets:

1) To the extent that the non-pumping facility, such as a Demand Response Program (DRP) represents price sensitive Demand that has not executed a Participating Load Agreement, such Demand can be bid to procure at a price, using the ordinary Non-Participating Load Demand Bid in DAM. In this manner the non-pumping facility is represented in the shape of the Demand Bid submitted by the SC. This option does not use the PSHU model. If such Demand Response Program is Non-Participating Load, it is settled at the Default Load Aggregation Point (LAP) price.

2) Participating Loads that can model themselves in the same On/Off states as pumps and execute a Participating Load Agreement (PLA), can participate like pumps as described in Section 2.1.4.2. For the non-pumping facilities that represent price sensitive Demand, many of the programs are triggered by specific events such as CAISO declaring a staged emergency. If the non-pumping facility Demand is dispatchable in RTM, then the Demand may utilize the PSHU, by responding to Real-Time prices. Non-pumping facilities may bid a similar Pumping Cost into the RTM to either consume Energy in RTM if not already scheduled in DAM or to curtail from the Day-Ahead schedule.

3) Aggregated Participating Loads that represent an aggregation of loads that are not at the same Location and have executed a Participating Load Agreement can submit an Energy Bid Curve, using the non-Participating Load Demand Bid in the DAM and submit a Bid into the Non-Spinning Reserve Market as described in Section 2.1.4.3. Under this model, CAISO adds a pseudo-generator to the CAISO network model to represent the Participating Load, to support bidding and dispatch of Non-Spinning Reserve. For Aggregated Participating Loads, CAISO adds a pseudo System Resource to the network model that allows Energy Bids to be modeled using the same functionality as exports from CAISO.

Attribute	Pump-Storage Model	Extended Non-Participating Load Model

---

[3] Demand Response Programs (DRPs) are one example of non-pumping facilities that can submit Participating Demand bids,

Model	Pump model as negative generator	Load operates as Non-Participating Load. Manual workaround by CAISO allows for participation as Non-Spinning Reserve
Number of Operating Bid Segments	Single segment – Pump is either on or off	Up to 10 segments
Aggregate physical resource?	No	Yes
Bid Component	Two part Bid: ▪ Shut-Down curtailment cost ▪ Pump Energy cost	One part Bid: ▪ Energy Bid curve
Base Load supported	No	No
Settlement	In DAM, Pump can only submit Bid to buy Energy. If scheduled, Pump Load is charged DAM LMP, If not scheduled in DAM, no charge. In RTM, any curtailment from DAM Schedule is paid nodal LMP plus Shut-Down curtailment cost, If Pump is not scheduled in DAM, Pump Load may offer to buy (i.e., to pump) in the RTM	CDWR Participating Loads have separate LAPs for DAM and RTM LMP calculation. For other Participating Loads, CAISO determines feasible level of LMP disaggregation on a case by case basis. DAM Schedule is settled at the DAM LMP. Difference between DAM Schedule and RTM Demand is settled at RTM LMP. Participating Load is not subject to Uninstructed Deviation Penalty.
Treatment in DAM	Modeled as a negative generator. Participating Load may only submit Bid to buy in DAM.	Energy is scheduled in DAM as Non-Participating Load. Participating Load is eligible to submit Bid for Non-Spinning Reserve, using pseudo-generators placed at the locations of the load.
Treatment in RTM	In RTM, Pump may offer to curtail from DAM Schedule (if scheduled in DAM) or offer to buy in RTM (if not scheduled in DAM).	Participating Loads determine RTM operating point by monitoring RTM LMPs. CAISO dispatches Non-Spinning

		Reserve as contingency only reserve, using pseudo-generators at the locations of the Participating Load. Actual response is expected as a reduction in Demand
Inter-temporal constraints	Yes • Minimum Up Time (minimum time to stay pumping after switching to that mode) • Maximum number of status changes (maximum number of times Pump can switch from pumping mode) • Daily Energy Limit	No
Load Ramping	No	No
Ancillary Service Eligibility	Eligible to provide Non-Spinning Reserve	Eligible to provide Non-Spinning Reserve

2.1.7   Non-Participating Loads

SCs may submit Bids for Non-Participating Loads in DAM to procure Energy. Such Bids may represent an aggregation of Loads and must be bid-in and Scheduled at an Aggregated Pricing Node. Non-Participating Load may not be bid-in to be curtailed in RTM.

2.1.8   Utility Distribution Companies

A Utility Distribution Company (UDC) is an entity that owns a Distribution System for the delivery of Energy, and that provides regulated retail electricity service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through an alternate retailer. A UDC has to execute a UDC Operating Agreement with CAISO.

2.1.9   Metered Subsystems

A Metered Subsystem (MSS) is a geographically contiguous electricity system located within a n Existing Zone Generation Trading Hub that has been operating as an electric utility for a number

of years prior to the CAISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration, and is subsumed within the CAISO Balancing Authority Area and encompassed by CAISO certified revenue quality meters at each interface point with the CAISO Controlled Grid and CAISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, that is operated in accordance with an MSS Agreement described in Section 4.9.1 of the CAISO Tariff.

To participate in the CAISO markets, MSSs must be represented by SCs, which can be the MSS itself.

2.1.10　Balancing Authority Areas

The CAISO Balancing Authority Area is one of the Balancing Authority Areas (BAAs) that is under the jurisdiction of the Western Electricity Coordinating Council (WECC). The CAISO Balancing Authority Area is directly connected with the following Balancing Authority Areas. The modeling description is also indicated:

- ➢ Bonneville Power Administration (BPA) – external
- ➢ PacifiCorp West – external
- ➢ Sierra Pacific Power – external
- ➢ Nevada Power – external
- ➢ Western Area Power Administration-Lower Colorado Region (WAPA-LCR) – external
- ➢ Sacramento Municipal Utility District –adjacent
- ➢ Arizona Public Service – external
- ➢ Salt River Project – external
- ➢ Imperial Irrigation District – external (candidate adjacent in future)
- ➢ Los Angeles Department of Water & Power – external (candidate adjacent in future)
- ➢ Comision Federal De Electricidad – external (candidate adjacent in future)
- ➢ Turlock Irrigation District – adjacent

In addition to the modeling of the CAISO Balancing Authority Area, there are three types of Balancing Authority Area modeling designations as briefly discussed below and further explained in the *BPM for Managing Full Network Model* :

- ➢ **External** – External Balancing Authority Areas are generally modeled in detail by using the same model for the EMS State Estimator and the CAISO Markets, including where New Participating Transmission Owners (PTOs) have converted their Existing Rights to

the CAISO Controlled Grid,[4] and Integrated Balancing Authority Areas. For external Balancing Authority Areas, imports and exports are modeled as injections at Scheduling Points in the detailed external network model, at tie points where Transmission Interfaces are interconnected, and in which Real-Time power flows developed in the State Estimator account for unscheduled as well as scheduled power flows. The CAISO models the resistive component for transmission losses in external Balancing Authority Areas but does not allow such losses to determine LMPs, since these losses are settled by the external Balancing Authority Areas.

➢ **New PTO Model**: For the CAISO Controlled Grid that is comprised of the New PTO's Converted Rights, the network model includes physical branches within external Balancing Authority Areas, and enforces the limits of the Existing Rights.

➢ **Integrated Balancing Authority Areas –** For external Balancing Authority Areas where there is sufficient data available or adequate estimates can be made for an IBAA, the FNM used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the network Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

The CAISO has executed a number of Interconnected Balancing Authority Areas Operating Agreements with interconnected Balancing Authority Areas to establish the relationship between CAISO and the neighboring Balancing Authority Area. Balancing Authority Areas that are eligible to participate in the CAISO Markets must do so through an SC (which can be the same entity).

2.1.11   Participating Transmission Owners

A Participating Transmission Owner (PTO) is a party to the Transmission Control Agreement whose application under Section 2.2 of the Transmission Control Agreement has been accepted and who has placed its transmission lines and associated facilities, and Encumbrances under

---

[4] The New PTOs' Converted Rights are in portions of the Los Angeles Dept. of Water and Power, Western Area Power Administration Lower Colorado, Arizona Public Service, PacifiCorp East, and Sierra Pacific Control Areas.

CAISO's Operational Control in accordance with the Transmission Control Agreement between CAISO and such PTO.

There are two types of Participating Transmission Owners:

➢ **Original** Participating TO – PTOs as of December 31, 2000
➢ **New** Participating TO – PTOs since January 1, 2001

2.1.12 System Resource

A System Resource is a group of resources, single resource, or a portion of a resource located outside of the CAISO Balancing Authority Area, or an allocated portion of a Balancing Authority Area's portfolio of resources that are either a static interchange schedule or directly responsive to that Balancing Authority Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the CAISO Balancing Authority Area, provided that if the System Resource is providing Regulation to the CAISO it is directly responsive to AGC. There are different types of System Resources:

1) Dynamic System Resource: A System Resource that is capable of submitting a Dynamic Schedule, including a Dynamic Resource-Specific System Resource. Unless otherwise noted, Dynamic System Resources are modeled and treated in the market similar to Generating Resources.

2) Non-Dynamic System Resource: A System Resource that is not capable of submitting a Dynamic Schedule, which may be a Non-Dynamic Resource-Specific System Resource.

3) Dynamic Resource-Specific System Resource: A Dynamic System Resource that is physically connected to an actual generation resource outside the CAISO Balancing Authority Area.

4) Non-Dynamic Resource –Specific System Resource: A Non-Dynamic System Resource that is physically connected to an actual generation resource outside the CAISO Balancing Authority Area.

2.1.13 Non-Generator Resources

Non-Generator Resources (NGRs) are Resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy.

More generally, NGRs are resources that operate as either generation or load and can be dispatched within their entire capacity range, inclusive of the generation and load. They are also constrained by an energy (MWh) limit to generate or consume energy on a continuous basis. NGRs include limited energy storage resources (LESR), and Generic resources. By modeling the generation range from negative to positive, the ~~ISO~~ NGR model provides NGRs the same opportunity as generators to participate in the CAISO energy and ancillary service markets subject to meeting eligibility requirements.

NGRs have the following characteristics:

➢ NGR is a resource that has a continuous operating range from a negative to a positive power injection; i.e., it can operate continuously by either consuming energy or providing energy, and it can seamlessly switch between generating and consuming electrical energy. An NGR functions like a generation resource and can provide energy and AS services. 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 ISO can use its NGR functionality to model a Limited Energy Storage Resource (LESR). However, NGR functionality is not limited to a storage resource. Any resource that can operate seamlessly from negative to positive can use this functionality.

  ➢ For an NGR, the energy limits (MWh) is 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 (SOC)), 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, the day ahead and real-time markets observe the energy limits in the energy and ancillary service optimizations.

  ➢ For NGRs using Regulation Energy Management, energy limits are observed in real-time economic dispatch only.

  ➢ The energy limits for NGRs are not required for the resource if the resource does not have that physical limitation; nevertheless, if the NGR resource has a stored energy limit, it must register the limit value with the ISO so that the ISO can observe the limit in the market. When resource energy limits are not provided, the ISO assumes that the NGR does not have these constraints. The resource owner and Scheduling

Coordinator must manage any resource energy constraints in order to comply with ISO dispatch instructions in the ISO Market.

➢ The algebraic power output of a NGR is limited between a minimum and a maximum capacity measured in MW. The minimum or maximum capacities can be negative. The maximum capacity is greater than the minimum capacity. For an NGR, 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.

➢ NGRs can provide energy and ancillary services (AS).
  ➢ NGRs can provide ancillary services (AS) continuously while they are charging or discharging. The dispatch of a NGR providing AS must employ a stored energy management scheme to manage the state of charge and ensure that there is sufficient stored energy in the device to dispatch to satisfy the AS when they are called upon.
  ➢ NGRs can provide regulation from anywhere within their regulation range.
  ➢ NGRs will be subject to Spin/Non-Spin No Pay based on the resource's energy limit on an after the fact basis.
➢ Generic NGR model has the ability to generate or consume energy. Market Participants can use the Resource Data Template (RDT) to register their resources under the Generic NGR model. This functionality allows Scheduling Coordinator to submit bids and Base Schedules for resources using Generic NGR model. Additionally, the Generic NGR model will be subject to Local Market Power Mitigation (LMPM) for its entire capacity (Pmax-Pmin). (see table below)

Dynamic competitive path assessment (DCPA) formula for NGR

On Regulation	IFM	RTM
Withheld capacity	$-\min(0,SF)*(\min(\min(UOL,URL)-RU-SR-NR,UEL,LSS)-\max(\max(LOL,LRL)-RD,LEL,GSS))$	$-\min(0,SF)*(\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,URL)-RU-SR-NR,UEL-SR-NR,LSS,EDMAX-\delta(RU+SR+NR))-\max(DOT(t-1)+RRD(DOT(t-1),T),\max(LOL,LRL)-RD,LEL,GSS,EDMIN-\delta*RD))$
Supply counter flow from potential pivotal supplier	$-\min(0,SF)*\max(\max(LOL,LRL)-RD,LEL,GSS)$	$-\min(0,SF)*\max(DOT(t-1)+RRD(DOT(t-1),T),\max(LOL,LRL)-RD,LEL,GSS,EDMIN-\delta*RD)$

	IFM	RTM
Supply counter flow from fringe competitive supplier	$-\min(0,SF)*\min(\min(UOL,URL)-RU-SR-NR,UEL,LSS)$	$-\min(0,SF)*\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,URL)-RU-SR-NR,UEL-SR-NR,LSS,EDMAX-\delta*(RU+SR+NR))$
Off Regulation	**IFM**	**RTM**
Withheld capacity	$-\min(0,SF)*(\min(UOL-SR-NR,UEL,LSS)-\max(LOL,LEL,GSS))$	$-\min(0,SF)*(\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,UEL)-SR-NR,LSS,EDMAX-\delta*(SR+NR))-\max(DOT(t-1)+RRD(DOT(t-1),T),LOL,LEL,GSS,EDMIN))$
Supply counter flow from potential pivotal supplier	$-\min(0,SF)*\max(LOL,LEL,GSS)$	$-\min(0,SF)*\max(DOT(t-1)+RRD(DOT(t-1),T),LOL,LEL,GSS,EDMIN)$
Supply counter flow from fringe competitive supplier	$-\min(0,SF)*\min(UOL-SR-NR,UEL,LSS)$	$-\min(0,SF)*\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,UEL)-SR-NR,LSS,EDMAX-\delta*(SR+NR))$

Where:

UOL	is the Upper Operating Limit
URL	is the Upper Regulating Limit
UEL	is the Upper Economic Limit
LOL	is the Lower Operating Limit
LRL	is the Lower Regulating Limit
LEL	is the Lower Economic Limit
GSS	is the Generating Self-Schedule
LSS	is the Load Self-Schedule
RU	is the Regulation Up self-schedule
RD	is the Regulation Down self-schedule
SR	is the Spinning Reserve self-schedule
NR	is the Non-Spinning Reserve self-schedule
$DOT(t)$	is the optimal dispatch at interval t
$RRU(DOT(t),T)$	is the upward ramp capability from $DOT(t)$ for interval duration T
$RRD(DOT(t),T)$	is the downward ramp capability from $DOT(t)$ for interval duration T
EDMAX	is the MAXGOTO ED/MD
EDMIN	is the MINGOTO ED/MD
δ	is the binary option to adjust ED/MD for AS

For consistency, the DCPA formula for Generating Resources as shown in table below.

Formula for Generating Resources

On Regulation	IFM	RTM
Withheld capacity	$-\min(0,SF)*(\min(\min(UOL,URL)-RU-SR-NR,UEL)-$ $\max(\max(LOL,LRL)-RD,ESS))$	$-\min(0,SF)*(\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,URL)-RU-SR-NR,UEL-SR-NR,EDMAX-\delta*(RU+SR+NR))-$ $\max(DOT(t-1)+RRD(DOT(t-1),T),\max(LOL,LRL)-RD,ESS,EDMIN-\delta*RD))$
Supply counter flow from potential pivotal supplier	$-\min(0,SF)*\max(\max(LOL,LRL)-RD,ESS)$	$-\min(0,SF)*\max(DOT(t-1)+RRD(DOT(t-1),T),\max(LOL,LRL)-RD,ESS,EDMIN-\delta*RD)$
Supply counter flow from fringe competitive supplier	$-\min(0,SF)*\min(\min(UOL,URL)-RU-SR-NR,UEL)$	$-\min(0,SF)*\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,URL)-RU-SR-NR,UEL-SR-NR,EDMAX-\delta*(RU+SR+NR))$
Off Regulation	IFM	RTM
Withheld capacity	$-\min(0,SF)*(\min(UOL-SR-NR,UEL)-$ $\eta*\max(LOL,ESS))$	$-\min(0,SF)*(\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,UEL)-SR-NR,EDMAX-\delta*(SR+NR))-$ $\max(DOT(t-1)+RRD(DOT(t-1),T),LOL,ESS,EDMIN))$
Supply counter flow from potential pivotal supplier	$-\min(0,SF)*\eta*\max(LOL,ESS)$	$-\min(0,SF)*\max(DOT(t-1)+RRD(DOT(t-1),T),LOL,ESS,EDMIN)$
Supply counter flow from fringe competitive supplier	$-\min(0,SF)*\min(UOL-SR-NR,UEL)$	$-\min(0,SF)*\min(DOT(t-1)+RRU(DOT(t-1),T),\min(UOL,UEL)-SR-NR,EDMAX-\delta*(SR+NR))$

Where:

ESS	is the Energy Self-Schedule
η	is a binary variable that is set if the resource is must-run because of ESS or spin self-provision

2.1.13.1   Non-Generator Resources Providing Regulation Energy Management

Under regulation energy management (REM), non-generator resources that require an offset of energy in the real time market to provide regulation can elect to participate only in the ISO's regulation markets. REM functionality will allow 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.

Non-Generator Resources providing Regulation Energy Management must register their minimum and maximum energy limits in order for the ISO to continuously optimize and balance the resource through Regulation energy.

Note that the buying and selling of energy in the real-time market supports the regulation obligation. NGRs using Regulation Energy Management do not participate in the ISO's energy market or operating reserves.

2.1.14   Pseudo-Tie

A Pseudo-Tie is a single resource physically located outside of the CAISO Balancing Authority Area, but contractually part of the CAISO Balancing Authority Area for purposes of production, ancillary services responsibility, operating jurisdiction, etc. Unless otherwise noted, Pseudo-Tie Generators are modeled and treated by the market similar to Generating Resources.

2.2   Products & Services

This subsection describes the types of products and services that are traded in the CAISO Markets. The *BPM for Market Instruments* describes these in greater detail.

2.2.1   Energy

SCs can supply Energy into the CAISO markets from the following resources:

- ➢ Generating Units
- ➢ System Units – associated with Metered Subsystems
- ➢ Physical Scheduling Plants – group of tightly coupled Generating Units

> ➢ Participating Loads (modeled as a PSHU)
> ➢ System Resources – located outside the CAISO Balancing Authority Area
> ➢ Multi-Stage Generating Resources
> ➢ Submission of Virtual Supply Bids into the Day-Ahead Market at eligible locations[5]

SCs can purchase Energy from the CAISO markets, via:

> ➢ Loads within the CAISO Balancing Authority Area
> ➢ Exports from the CAISO Balancing Authority Area
> ➢ Submission of Virtual Demand Bids into the Day-Ahead Market at eligible locations.

2.2.2   Ancillary Services

The following types of Ancillary Services (AS) products are procured in the CAISO Markets. Section 4 of this BPM describes these Ancillary Services and their requirements in greater detail:

> ➢ Regulation Up (must be synchronized and able to receive AGC signals, and be able to deliver the AS Award within 10 minutes[6] based on the regulating ramp rate of the resource[7])
> ➢ Regulation Down (must be synchronized and able to receive AGC signals, and be able to deliver the AS Award within 10 minutes based on the regulating ramp rate of the resource)
> ➢ Spinning Reserve (must be synchronized, be able to deliver the AS Award within 10 minutes)
> ➢ Non-Spinning Reserve (must be able to deliver the AS Award within 10 minutes)

2.2.3   Residual Unit Commitment Capacity

Residual Unit Commitment (RUC) Capacity is the positive difference between the RUC Schedule and the greater of the Day-Ahead Schedule and the Minimum Load level of a resource. The RUC Price and the RUC Capacity are determined based on the RUC Availability

---

[5] Eligible locations for Virtual Bids submission are published on the CAISO web-site.

[6] In DAM, AS are procured for each Trading Hour. In RTM, AS from resources that are Dynamic System Resources are procured for each 15 minute interval. For resources that are identified as Non-Dynamic System Resources, AS capacity will be procured for the hour. In either case, when AS is dispatched, the associated Energy must be delivered within 10 minute according to the AS definition.

[7] Tariff Sections 8.4.1.1 and 30.5.2.6.1 provides that Ancillary Services Bid for Regulation must contain an upward and downward range of generating capacity over which the resource is willing to provide Regulation within a range from a minimum of 10 minutes to a maximum of 30 minutes. Initially the CAISO sets this requirement at 10 minutes.

Bids. Virtual Bids are not considered in RUC, but they may influence the RUC outcome based on the amount of unit commitment, Virtual Awards, and physical schedules awarded in the IFM.

RUC Schedule is the total MW per hour amount of capacity committed by RUC, including the MW per hour amount committed in the Day-Ahead Schedule.

2.2.4   Congestion Revenue Rights

Congestion Revenue Rights (CRRs) are financial instruments that may be used by their holders to offset the possible Congestion Charges that may arise in the IFM Day-Ahead Market for Energy. CRRs are settled based on the Marginal Cost of Congestion component of LMPs derived through IFM. Due to Virtual Bids having the ability to impact Congestion in the Day-Ahead Market, it is possible for an adjustment of CRR revenues to occur for CRR Holders that are also Convergence Bidding Entities (CBEs). This adjustment is called the CRR Settlement Rule and is explained in more detail in attachment F of the appendices.

The *BPM for Congestion Revenue Rights* describes these rights in greater detail.

2.3   CAISO Markets

This subsection presents a high level description of the Day-Ahead and Real-Time Markets. Market bidding timelines and primary activities are also discussed. Refer to Exhibit 2-1.[8]

---

[8] Trading Day-1 refers to the time when the Extra Long Commitment takes place, which happens after the Day Ahead market is complete, from Trading Day-1 1000 to 1300. The 'extremely long unit commitment' process takes place at 1500, and is still part of the Trading Day-1 process even though it applies to the subsequent day. Please see section 6.8 for further detail.

Begin Markets

Day-Ahead Market

Real-Time Market

TY-120	Open CRR Market to Process Annual CRRS		
TM-30	Transmission Outage Requests for Monthly CRRs		
TM-31	Monthly Resource Adequacy Verification		
Every 3 weeks	Update, Test & Release Full Network Model to Production		
TM-15	Open CRR Monthly Market		
Starting TD-7	Daily Update of Demand		
6. TD-7	Open Day-Ahead Market and Accept DAM Bids		
TD-3	Review Outage Requests & Create Outage Schedules		
TD-2 1600	Determine OTCs (TTC-Derates)		
TD-2 1800	Prepare/Publish Demand Forecasts & AS Requirements		
TD-2 1800	Publish OTCs		

Day-Ahead Market column:

- TD-1 0000 — Update Master File
- TD-1 0530 — Compile PIRP Data Collect 7-day True Wind Forecast
- TD-1 0900 — Update/Publish ACCs Determine/Publish ATCs Determine (OTC-ETC)
- TD-1 1000 — Validation of ETC/TOR/CVR is Completed
- TD-1 1000 — Close Day-Ahead Market Clean and Generated Bid Set
- 6.5 6.6 6.7 TD-1 1000 — Update/Publish OTCs Determine RMR & MPM Run IFM & RUC
- TD-1 1300 — Post DAM Validation of Physical Inter-SC Trades & System Load Forecast
- TD-1 1300 — Update/Publish ACCs Publish DA Schedules Submit Etags for DA
- 7. TD-1 1300 — Open Real-Time Market for 0100 to 2400 on Trading Day
- 6.8 TD-1 1500 — Commit Extremely Long Start Units

Real-Time Market column:

- TD-1 1500 — Validate Etags against Schedules Publish Interchange Schedules
- TD-1 1500 — Perform Control Area Checkout
- TD TH-75' — Accept Schedule Changes for ETCs with Priorities, RT ETC Schedules, Energy Bids
- TD TH-75' — Close Real-Time Market Generate Clean Bid Set
- 7.4 TD TH-67.5' — Run Hourly MPM/RRD Followed by HASP
- TD TH-67.5' — Post RTM Validation of Physical Inter-SC Trades
- TD TH-45' — Publish Hourly System Resource Schedules & AS Awards
- 7.5 7.6 TD TH-67.5' — Run Every 15-minute RTUC with First Run Same as HASP to Produce AS Awards & Commit Fast/Short Start Units
- 7.7 TD TH-52.5' — Run Hourly STUC with Second Run of RTUC to Commit Medium/Short Start Units

Right-most column:

- TD every 30 min — Update Demand Forecast
- TD TH-20' — ETC
- TD every 5-minutes — Run RTED 7.8
- TD every 5 minutes — Review RTED Results & Issue Dispatch Instructions

After Markets

TY = Trading Year	ACC = Available Contract Capacity	ETC = Existing Transmission Contract
TM = Trading Month	CRR = Congestion Revenue Right	TOR = Transmission Ownership Right
TD = Trading Day	OTC = Operating Transfer Capability	CVR = Converted Right
TH = Trading Hour	TTC = Total Transfer Capability	ATC = Available Transfer Capability

Exhibit 2-1: CAISO Markets – Overview Timeline

The manual ELC process is in addition to the RUC process and is conducted as part of the Day Ahead Operating Procedures and considers Bids submitted in the DAM for the operations two days out. Any commitment outside this time frame of an ELC resource would be an Exceptional Dispatch.

2.3.1   Day-Ahead Market Processes

Bidding for the Day-Ahead Market (DAM) closes at 1000 hours on the day before the Trading Day and consists of a sequence of processes that determine the hourly Market Clearing Prices for Energy (including physical and Virtual Bids) and AS, as well as the incremental procurement in RUC while also mitigating Bids from to address non-competitive constraints. These processes are co-optimized to produce a Day-Ahead Schedule at least cost while meeting local reliability needs. The CAISO ensures that Virtual Bids (Supply and Demand) are not passed from the IFM to RUC or RTM.

RMR dispatches to meet local reliability requirements are determined manually prior to the start of the market and are incorporated as constraints into the market processes. In addition to that, RMR dispatch requirement for Condition 1 RMR resources can also be determined by the MPM process as described further in section 6.1.7.1. The extent Condition 2 RMR units are considered in the market, they are considered based on their cost- based RMR Proxy Bids.

TTC pertains to all interties, and to significant corridors such as Path 15 and Path 26. The TTC is updated for the DAM and RTM as needed. The details of TTC calculation and timeline are provided in Section 5.25.25.2. TTC reduction cutoff 0900 hours. However uprates are allowed up to 1000 hours

The prices resulting from these processes are used for the Day-Ahead Market Settlement. The timeline for the Integrated Forward Market is shown in Exhibit 6-1. The following subsections present an overview of these processes for the Trading Day. Further details are presented in Section 6, Day-Ahead Market Processes.

2.3.1.1   Day-Ahead Market Power Mitigation (MPM)

MPM is the first market process in the Day-Ahead Market. The MPM function consists of a test to determine which Bids to mitigate to address non-competitive constraints. If the test fails, the MPM mitigates the affected Bids for the relevant Trading Hours of the Trading Day. The MPM function is performed prior to the Integrated Forward Market process. Please refer to Section 6.5, Market Power Mitigation for a more detailed description of this process.

2.3.1.2   Integrated Forward Market

The IFM is a market for trading physical and virtual Energy and Ancillary Services for each Trading Hour of the next Trading Day. IFM uses Clean Bids from SIBR[9] (i.e., that pass the SIBR validation rules) and the mitigated Energy Bids to the extent necessary after MPM in order to

---

[9] This process is described in more detail in the *BPM for Market Instruments*, Section 8.

clear physical and Virtual Supply and physical and Virtual Demand Bids and to procure AS to meet one-hundred percent of CAISO's AS requirements at least cost over the Trading Day. Refer to Section 6.6, Integrated Forward Market, for further details.

2.3.1.3   Residual Unit Commitment

Residual Unit Commitment is a reliability function for committing resources and procuring RUC Capacity not scheduled in the IFM (as physical Energy or AS capacity.) RUC Capacity is procured in order to meet the difference between the CAISO Forecast of CAISO Demand (CFCD) (including locational differences and adjustments) and the Demand scheduled in the IFM, for each Trading Hour of the Trading Day. In addition, RUC anticipates supply and demand over a longer look-ahead time period (default to 72 hours but can be up to 168 hours, compared to 24 hours in the IFM). This allows RUC issue advisory commitment instructions for Extremely Long-Start Resources which may not be considered in the IFM due to their long start-up times. These advisory instructions are considered as part of the ELS commitment process described in Section 6.8 below. In order to reduce cycling of resources through the transition from one day to another, RUC looks-ahead beyond the binding 24 hour period as it procures capacity and make commitment decisions for the applicable binding time horizon, taking into account expected needs in the forward days beyond the 24 hour time period. Refer to Section 6.7, Residual Unit Commitment. The CAISO, however, runs the RUC process for every Trading Day regardless of the difference between the CFCD and the Scheduled Demand in the IFM. The objective of the RUC is to ensure sufficient physical capacity is available and committed at least cost to meet the adjusted CAISO Forecast of CAISO Demand for each hour of the next Trading Day, subject to transmission and resource operating constraints. RUC achieves this objective by minimizing the total of Start-Up Costs, Minimum Load Costs and incremental availability costs (i.e., RUC Availability Bids). As a result, it is possible that when RUC runs RUC may procure Capacity and possibly commit resources even though the CAISO Forecast of CAISO Demand prior to the taking into account the locational differences and adjustments, is equal or less than the Scheduled Demand of the SCs resulting from the IFM. This can happen because the locational quantity of load scheduled in the IFM may be different than the locational quantity of load after distributing the adjusted CAISO Forecast of CASIO Demand in RUC. In addition, RUC may need to commit resources to the extent virtual supply displaces physical supply in the IFM.

Resources receive a binding Start-Up Instruction from RUC (if committed by RUC), only if they must receive start up instruction in DAM to meet requirements in RTM. Other resource commitment decisions are determined optimally in the RTM.

2.3.1.4   Extremely Long-Start Commitment

The commitment of resources that require a Start-Up Time of greater than 18 hours or notification earlier than the publication of the DAM is considered both in the RUC (explained in the previous section) and in the Extremely Long-Start Resource commitment process. Extremely Long- Start resources receive advisory startup-up instructions through the RUC process. Such start-up instructions are confirmed and made binding and communicated manually by CAISO operators. Refer to Section 6.8, Extremely Long-Start Resource commitment, for the details of this process.

2.3.2   Real-Time Processes

The primary goal of the RTM is to identify supplies to meet the CAISO Forecast of CAISO Demand and export schedules.

Bidding for the Real-Time Market (RTM) closes 75 minutes before the beginning of each Trading Hour (which in turn begins at the top of each hour). A sequence of processes determines the Market Clearing Prices for each Trading Hour. The prices resulting from these processes are used for the Real-Time Market Settlement.

Virtual Bids and Awards are not considered in the RTM.

The following subsections present an overview of these processes for the Trading Hour. Further details are presented in Section 7, Real-Time Processes.

2.3.2.1   Market Power Mitigation

The MPM functions for Real-Time are analogous to the same function that is performed for the DAM. For Real-Time, the MPM functions cover the Trading Hour and the resultant mitigated Bids are then used by the remaining Real-Time processes. Refer to Section 7.4, MPM for Real-Time.

The Day-Ahead Market and the Real-Time Market require separate Bid submissions. MPM re-evaluates all Bids in Real-Time.

Mitigation in the DAM is a separate process from Real-Time mitigation. As a result, a Bid could be mitigated in the DAM but not be mitigated in the RTM, and vice versa.

2.3.2.2   Hour-Ahead Scheduling Process

The Hour-Ahead Scheduling Process (HASP) is a process for scheduling Energy and AS based on the Bids submitted into the HASP from Scheduling Points. Refer to Section 7.5, Hour-Ahead Scheduling Process.

HASP is performed immediately after the Real-Time MPM. HASP produces HASP Advisory Schedules and advisory AS Awards for most resources except for resources with accepted Self-Schedule Hourly Blocks and awarded
Economic Hourly Block Bids (but excluding an Economic Hourly Block Bid with Intra-Hour option), for which HASP Block Intertie Schedules are produced. All HASP Schedules for the Trading Hour are published approximately 45 minutes before the start of each Trading Hour.

HASP Block Intertie Schedules for the applicable HASP Trading Hour (i.e., between T and T+60 minutes) are determined on an hourly basis instead of on a 15-minute basis. This is accomplished by enforcing constraints that ensure that the HASP Block Intertie Schedules for the 15-minute intervals are equal.

2.3.2.3   Real-Time Unit Commitment

Real-Time Unit Commitment (RTUC) is a market process for committing Fast and Short-Start Units and awarding additional AS from Dynamic System Resources at 15-minute intervals. The RTUC function runs every 15 minutes and looks ahead in 15-minute intervals spanning the current Trading Hour and next Trading Hour. Refer to Section 7.6, Real-Time Unit Commitment. Also refer to Exhibit 6-2, Generating Unit Commitment Selection by Application, for a summary of the Unit Commitment processes.

The Fifteen Minute Market (FMM) is the second interval of the RTUC and its results produce the binding FMM

2.3.2.4   Short-Term Unit Commitment

Short-Term Unit Commitment (STUC) is a reliability function for committing Short and Medium Start Units to meet the CAISO Forecast of CAISO Demand. The STUC function is performed hourly and looks ahead three hours beyond the Trading Hour, at 15-minute intervals. Refer to Section 7.7, Short-Term Unit Commitment.

2.3.2.5   Real-Time Economic Dispatch

The Real-Time Economic Dispatch (RTED) is a market process that dispatches Imbalance Energy and dispatches Energy from AS and normally runs automatically every five minutes to

produce Dispatch Instructions. The following two alternative modes to RTED are invoked under abnormal conditions:

➢ Real-Time Contingency Dispatch (RTCD)
➢ Real-Time Manual Dispatch (RTMD)

Refer to Section 7.8, Real-Time Economic Dispatch, and Attachment A.2, Security Constrained Economic Dispatch, for a description of the Dispatch algorithm.

2.3.2.5.1   Real-Time Contingency Dispatch

The Real-Time Contingency Dispatch (RTCD) function executes upon CAISO Operator action, usually following a Generating Unit or transmission system Contingency. The RTCD execution is for a single 10-minute interval and includes all Operating Reserves and all Real-Time Energy Bids in the optimization process. Refer to Section 7.9, Real-Time Contingency Dispatch.

2.3.2.5.2   Real-Time Manual Dispatch

The Real-Time Manual Dispatch (RTMD) function executes upon CAISO Operator action, usually when RTED and RTCD fail to provide a feasible solution. The RTMD is manually executed every five minutes for a single 5-minute interval. Refer to Section 7.10, Real-Time Manual Dispatch.

2.3.2.6   Market Orchestration

Market Participants can get important general market event information such as Real Time Market has opened, Day Ahead Market has closed, etc either through the CAISO portal or can these events can be sent as messages in the form of .xml files. CAISO has created a process for Market Participants interested in getting xml messages sent to them. Market Participants will need to download a registration form from the CAISO website. Market Participants will provide their end point information in the form and email the form to mns.registration@caiso.com. CAISO will process the information and set up the entities so the xml market event messages can be sent to the registered Market Participant end point.

2.4   Roles & Responsibilities

This subsection identifies and describes the basic roles and responsibilities of the entities that participate in the CAISO Markets.

2.4.1   Utility Distribution Companies

This section is based on CAISO Tariff Sections 4.4.2, 4.4.3, 4.4.4, 4.4.5.1, 4.4.5.2, 4.4.5.3, 4.4.5.4 and 19.2

Entities that have entered into UDC Operating Agreements with CAISO must operate their Distribution Systems at all times in accordance with Good Utility Practice that ensures safe and reliable operation. The UDCs must inform their SCs of: (1) all operational information made available to UDCs by CAISO and (2) all operational information made available to CAISO by the UDCs.

UDC responsibilities include the following:

> ➢ Operate its facilities so as to avoid adverse impacts to CAISO
> ➢ Submit significant maintenance and Outage schedules with the interconnected TO and CAISO
> ➢ Coordinate electrical protective systems with CAISO
> ➢ Coordinate significant emergency system restoration with CAISO
> ➢ Maintain records of System Emergencies and maintenance
> ➢ Coordinate expansion planning, system surveys, and inspections with CAISO
> ➢ Submit Demand Forecasts to CAISO

2.4.2   Metered Subsystems

This section is based on CAISO Tariff Sections 4.9.4 and 4.9.5.

Entities that have entered into a written agreement with CAISO can participate in the CAISO Markets as MSSs. Each MSS Operator must operate its MSS at all times in accordance with Good Utility Practice that ensures safe and reliable operation. MSS Operators must inform their SCs of: (1) all operational information made available to the MSS Operator by CAISO and (2) all operational information made available to CAISO by the MSS Operators.

MSS Operator responsibilities include the following:

> ➢ Operate its facilities so as to avoid adverse impacts on the CAISO Controlled Grid
> ➢ Coordinate Generation and transmission facility maintenance and Outage schedules with interconnected PTOs and the CAISO
> ➢ Coordinate electrical protective systems with CAISO
> ➢ Maintain reliability within the MSS
> ➢ Coordinate Congestion Management and transmission line Outages within or at the boundary of the MSS

➢ Respond to CAISO directives during System Emergencies

➢ Coordinate significant system restoration with CAISO

➢ Maintain records of System Emergencies and maintenance

➢ Coordinate expansion planning, system surveys, and inspections with CAISO

➢ Respond to Ancillary Services Obligations

➢ Submit Demand Forecasts to CAISO

2.4.2.1   MSS System Unit

An MSS Operator may aggregate one or more Generating Units and/or Participating Loads as a System Unit (subject to CAISO approval). CAISO has Dispatch control over the System Unit as a whole but has control over individual Generating Units within the System Unit for Regulation purposes only.

2.4.2.2   MSS Elections & Participation in CAISO Markets

This section is based on CAISO Tariff Section 4.9.13.

MSS entities must make an annual election on the manner in which the MSS intends to participate in the CAISO Markets. The MSS entity must make annual choices for each of the following:

➢ Choose either net settlements or gross settlements. This election must be made 60 days in advance of the annual CRR allocation process in accordance with CAISO Tariff Section 4.9.13.1.

➢ Choose to Load-follow or not Load-follow with its Generating Units. This annual election must be made 6 months in advance of the implementation of Load-following capability. MSS entities who choose to Load-follow:

  o Prior to making an election contact Client Services and Stakeholder Affairs for information on Load-following at: ISOClientRepresentatives@caiso.com

  o The transition must occur on the first of the month. See BPM for Reliability Requirements section 3.4 "Load-Following Metered Subsystem" for specific resource adequacy provision.

➢ Choose to have its Load participate in the Residual Unit Commitment procurement process and therefore CAISO procures RUC Capacity to meet the MSS Operators' needs, or not have its Load participate in the RUC procurement process, in which case CAISO will not procure RUC Capacity for the MSS. MSSs that elect to Load-follow must not participate in the RUC procurement process. This election must be made 60 days in

advance of the annual CRR allocation process in accordance with CAISO Tariff Section 31.5.2.

➢ Choose to charge the CAISO for Emission Costs. This annual election must be made on November 1 for the following calendar year in accordance with CAISO Tariff Section 11.7.4.

Annual elections must be sent to Regulatory Contracts pursuant to the MSS Agreement. These elections may be scanned into a Portable Document Format (PDF) and e-mailed to RegulatoryContracts@caiso.com with a hard copy original to follow.
Mail to:

California Independent System Operator Corporation

 Regulatory Contracts

250 Outcropping Way

Folsom, CA 95630

2.4.2.3   Permitted MSS Election Options

The table below lists the permitted combinations of MSS election options.

Load Following	RUC Participation	CRR Allocation and Settlement Election
No	No	Gross
No	No	Net
No	Yes	Gross
No	Yes	Net
Yes	N/A	Net
Yes	N/A	Gross

2.4.3   Participating Transmission Owners Information

Each PTO must provide operational information to CAISO with respect to transmission facilities that have been turned over to CAISO Operational Control, including ETCs (also referred to herein as "ETCs") that are Encumbrances of the CAISO Controlled Grid.

The CAISO Tariff addresses PTOs' operational information-sharing responsibilities in Sections 4.3 and 9.

2.4.3.1   Local Reliability Criteria

CAISO operates and plans for its operation during the running of the markets, consistent with applicable Reliability Criteria set forth by NERC/WECC. In addition, CAISO operates and plans based on the Local Reliability Criteria provided to CAISO by each PTO.

Further information is provided in the *BPM for Reliability Requirements*.

2.4.3.2   Transmission Outages

This is based on Section 9 of the CAISO Tariff, in particular Section 9.3.1 (CAISO Outage Coordination Office).

The CAISO Outage Coordination Office must be notified by PTOs of all transmission facility Outages and deratings in a timely manner as described in the *BPM for Outage Management*. This information is required for reliable power system operation and optimal market operation. Reporting and CAISO approvals depend on the nature of the Outage:

- ➢ PTO planned transmission Maintenance Outage
- ➢ CAISO request for transmission Maintenance Outage
- ➢ Forced Outage
- ➢ Generator request for Maintenance Outage

Planned Maintenance Outage is assumed to occur based on the planned timeline of the approved Outage and is reflected in the market timeline subject to confirmation 72 hours in advance.

2.4.4   Participating Generators & Participating Loads

Participating Generators and Participating Loads and Demand Response providers are responsible for submitting their Outage plans in accordance with the guidelines presented in the *BPM for Outage Management*.

This section is based on Section 9 of the CAISO Tariff, in particular Section 9.3.6.

2.4.4.1   Physical Scheduling Plants

A Physical Scheduling Plant (PSP) is modeled as one individual resource, using the aggregated resource approach. The following features are available:

- ➢ Aggregated Energy constraint submitted with Bid

- ➢ Aggregated PMax and PMin submitted to Master File

➢ Aggregated Ramp Rate – must be updated by the Scheduling Coordinator to reflect individual unit conditions

➢ Aggregated Regulation service – based upon AS certification

➢ CAISO sends aggregated regulation signal to PSP for allocation via Generation Distribution Factors (GDFs) to the individual units

2.4.5   Scheduling Coordinator Responsibilities

This section is based on CAISO Tariff Section 4.5.2.2, SC Representing Convergence Bidding Entities, Section 4.5.3, Responsibilities of a Scheduling Coordinator and Section 4.5.4, Operations of a Scheduling Coordinator

Each Scheduling Coordinator (SC) is responsible for the following. Additional information is presented in the *BPM for Scheduling Coordinator Application & Responsibilities*:

➢ Obligation to pay CAISO's charges in accordance with the CAISO Tariff

➢ Depending on the Markets in which the SC wants to participate, submit Bids in the Day-Ahead Market and the Real-Time Market in relation to Market Participants for which it serves as an SC; SCs provide CAISO with intertie schedules prepared in accordance with all NERC, WECC, and CAISO requirements, including providing ~~e-Tag~~E-Tags for all transactions

➢ Coordinating and allocating modifications in Demand and exports and Generation and imports at the direction of CAISO in accordance with the CAISO Tariff Section 4.5.3.

➢ Submitting any applicable Inter-SC Trades that the Market Participants intend to have settled through the CAISO Markets, pursuant to the CAISO Tariff

➢ Tracking and settling all intermediate trades, including bilateral transactions and Inter-SC Trades, among the entities for which it serves as SC

➢ Providing Ancillary Services in accordance with the CAISO Tariff

➢ Submitting to CAISO the forecasted weekly peak Demand on the CAISO Controlled Grid and the forecasted Generation capacity. The forecasts cover a period of 12 months on a rolling basis

➢ Complying with all CAISO Business Practice Manuals and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the Business Practice Manuals

➢ Identifying any Interruptible Imports included in its Bids or Inter-SC Trades

➢ Submitting Schedules for Participating Intermittent Resources consistent with the CAISO Tariff

➢ Submitting Bids so that any service provided in accordance with such Bids does not violate environmental constraints, operating permits or applicable law. All submitted Bids must reflect resource limitations and other constraints as such are required to be reported to the CAISO Control Center

➢ Other than a Scheduling Coordinator that engages solely in financial activity (i.e. Virtual Bidding on behalf of Convergence Bidding Entities and Inter-SC Trades), each SC operates and maintains a 24-hour, seven days per week, scheduling center. Each SC designate a senior member of staff as its scheduling center manager who is responsible for operational communications with CAISO and who has sufficient authority to commit and bind the SC

➢ Scheduling Coordinator is responsible for providing GDF's for Aggregate Generating Resources. Default GDFs will be used in absence of this data. These default GDF's are derived from the State Estimator and they are maintained in the GDF Library.

➢ The Scheduling Coordinator is responsible for registering and bidding resources as Multi-Stage Generating Resources pursuant to Section 27.8 of the CAISO Tariff. Information on registration of Multi-Stage Generating Resources is available at: http://www.caiso.com/27bd/27bdc1ce2f430.html

➢ SCs submit Bids for imports of Energy and Ancillary Services for which associated Energy is delivered from Dynamic System Resources located outside of the CAISO Balancing Authority Area, provided that:

   ▪ Such dynamic scheduling is technically feasible and consistent with all applicable NERC and WECC criteria and policies

- All operating, technical, and business requirements for dynamic scheduling functionality, as posted in standards on the CAISO Website[10], are satisfied

- The SC for the dynamically scheduled System Resource executes an agreement with CAISO for the operation of dynamic scheduling functionality

- All affected host and intermediary Balancing Authority Areas each execute with CAISO an Interconnected Balancing Authority Area Operating Agreement or special operating agreement related to the operation of dynamic scheduling functionality

- SCs need to register Proxy Demand Resources (PDR) resources with CAISO.

- SCs must submit GDFs with the bids for PDRs with dynamic GDFs. For PDRs with static GDFs, SCs are expected to provide GDFs during registration.

➢ SCs need to register with the CAISO to submit Virtual Bids on behalf of registered Convergence Bidding Entities.

- SCs need to identify which Convergence Bidding Entities (CBEs) it will represent (including itself, if applicable). SC/CBE relationships will be modeled in the Master File for the basis of Position Limits.

- The parent SC (i.e. corporate or governmental entity contracting with the CAISO to participate in the CAISO Markets) must ensure collateral is provided sufficient to cover simultaneous CRR and Virtual Bid credit exposure as well as all other market activity.

➢ SCs need to submit information regarding affiliates that participate in the CAISO Markets and information concerning any Resource Control Agreements on forms and at times specified in the Business Practice Manual for Scheduling Coordinator Certification & Termination and Convergence Bidding Entity Registration & Termination. This information is needed for proper operation of the dynamic competitive path assessment.

2.5   Market Information

This section summarizes and describes the common information that is used by the Day-Ahead and Real-Time processes.

---

[10] The relevant information can be found at: http://www.caiso.com/docs/09003a6080/2f/c8/09003a60802fc882ex.html

2.5.1   Resource Static Data

Static data is information that is expected to change infrequently. See Attachment B of *BPM for Market Instruments*, for Master File reference data.

2.5.2   Bids

Bids are submitted by SCs for each of the CAISO Markets. These Bid components are summarized as follows and are described further in the *BPM for Market Instruments,* Section 5:

   ➢ Start-Up Time and Start-Up Cost
   ➢ Minimum Load Cost
   ➢ Transition Costs
   ➢ RUC Availability Bid
   ➢ Regulation Up and Regulation Down Capacity Bids
   ➢ Regulation Up and Regulation Down Mileage Bids
   ➢ Spinning Reserve and Non-Spinning Reserve Bids
   ➢ Import Bid and Export Bid
   ➢ Energy Bid Curve and daily Energy Limits
   ➢ Generation Distribution Factors
   ➢ Ramp Rates
   ➢ Virtual Supply and Virtual Demand Bids in Day-Ahead Market.

SIBR processes Bids through a series of validation rules and, in the case of Virtual Bids, submits such bids to a credit check prior to Market Close. A warning is issued from SIBR if the Bid is not valid and the Scheduling Coordinator is given an opportunity to cancel the Bid and resubmit the bid, time permitting.   After Market Close, SIBR creates Clean Bids, or generates Bids (described in more detail in the *BPM for Market Instruments,* Section 8) in accordance with CAISO Market rules.   Clean Bids and Generated Bids are pushed to the DAM market processes. Additional detail regarding the Bid validation process is in the BPM for Market Instruments.

2.5.2.1   Self-Schedules

SCs may submit Self-Schedules for Demand or Supply for each Trading Hour of the Trading Day in addition to or without providing Economic Bids for Energy. Self-Schedules of exports are permitted. However, two different levels of schedule priorities are determined depending on if the Self-Scheduled export is explicitly being supported by energy scheduled from non-Resource Adequacy capacity or not. For a Self-Scheduled export that is explicitly supported by non-Resource Adequacy Capacity, the export has the same priority as the Self-Scheduled Demand in the Day-Ahead Market.   For a Self-Scheduled export that is not explicitly supported by non-

Resource Adequacy Capacity, the export is still a price taker but has a lower priority than Self-Scheduled CAISO Demand in the Day-Ahead Market. In the RTM an export can be Self-Scheduled as well. However, in the RTM, a Self-Scheduled export that is explicitly supported by Energy from either non-Resource Adequacy Capacity or Resource Adequacy Capacity that has not been committed in the RUC process has an equal priority as CAISO Forecast of CAISO Demand in the RTM. Any Self-Scheduled export that is not explicitly supported by Energy from either non-Resource Adequacy Capacity or Resource Adequacy Capacity that has not been committed in the RUC process has a lower priority than CAISO Forecast of CAISO Demand in the RTM. For PDRs, SCs can submit Energy Self-Schedules for a trading hour only if:

1) There is a Non-Spin self-provision bid for the same trading hour; and

2) The total Self-Scheduled quantity is equal to the registered Pmin of the PDR.

Reliability Demand Response Resources are not allowed to submit a Self-Schedule Bid in Real-Time. Day Ahead schedules for the resource will automatically become a self-schedule for the applicable Real-Time hour. Market participant must ensure RDRR DA schedules are followed based upon notification through CMRI per BPM for Market Instruments section 5.1.3. A Self-Schedule is modeled as an Energy Bid with an extreme price (penalty price) that effectively provides scheduling priority over Economic Bids for Energy.

SCs may also submit in the DAM only an Intertie Block Bid (i.e., a Bid from a System Resource that offers the same quantity across multiple, contiguous hours of the Trading Day). Intertie Block Bids include (in addition to the Energy Bid Curve, which can consist of Economic Bids or Self-schedules) the number of consecutive Trading Hours that any portion of the Energy Bid, which can consist of Economic Bids or Self-schedule may be accepted at the minimum. An Intertie Block Bid can either be submitted as a Self-Schedule or an Economic Bid but not as a combination of both. The particular CAISO Market process to which the Self-Schedule is submitted evaluates such Bids in terms of its scheduling priority, as described in this BPM, Section 6.6.45.3, instead of Bid price. For Settlement purposes, Self-Schedules are Price Takers:

  ➢ Self-Schedules for Supply of Energy are paid the relevant LMP as determined by the CAISO Market

  ➢ Self-Schedules for Demand of Energy are charged the relevant LMP as determined by the CAISO Market

During uneconomic adjustments, the Self-Schedules have a different priority to ETC/CVR and TOR Self-Schedules as are listed in Section 6.6.45.3, Scheduling Priorities. Refer to Section

7.5.3.2, RTM Self-Schedules and Section 7.5.3.3, Self-Schedules in HASP, for additional information.

If an Energy Bid is submitted with a Self-Schedule from the same resource for the same Trading Hour, the Energy Bid must start at the end of all relevant Self-Schedules stacked back-to-back in decreasing scheduling priority order. Otherwise, the Energy Bid must start at the applicable Minimum Load (zero for System Resources).

A Self-Schedule indicates that the resource is self-committed, i.e., the DAM/RTM unit commitment applications model the resource as online in the relevant intervals. A Self-Schedule, although at a higher priority than Economic Bids, may be reduced through uneconomic adjustments down to the relevant Minimum Load in the DAM/RTM if this is necessary to resolve network constraints. Self-Schedules may also be adjusted by the DAM/RTM, as necessary, to resolve any resource operational or inter-temporal constraint violations. All Self-Schedules that are Scheduled will be settled at the applicable DAM/RTM LMP.

Self-committed resources are not eligible for recovery of their Start-Up Costs for their self-commitment period. Self-committed resources are also not eligible for recovery of their Minimum Load Costs during the intervals when they self-commit. Such resources, are however, still eligible for conditional recovery of un-recovered Bid Costs through the Bid Cost Recovery mechanism. This is described in more detail in the *BPM for Settlements and Billing, in the following configuration guides:*
(a) Pre-calculation Start-up and Minimum Loads Cost
(b) Pre-calculation IFM Net Amount
(c) Pre-calculation RUC Net Amount, and
(d) Pre-calculation RTM Net Amount

2.5.2.2   Wheeling

The CAISO Tariff defines Wheeling as "Wheeling Out or Wheeling Through"

Wheeling Out is defined to mean: "Except for Existing Rights exercised under an Existing Contract in accordance with Section 16.1, the use of the CAISO Controlled Grid for the transmission of Energy from a Generating Unit located within the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO."

Wheeling Through is defined to mean: "Except for Existing Rights exercised under an Existing Contract in accordance with Section 16.1, the use of the CAISO Controlled Grid for the

transmission of Energy from a resource located outside the CAISO Controlled Grid to serve a Load located outside the transmission and Distribution System of a Participating TO."

These tariff definitions specify transactions for which the ISO collects Wheeling Access Charges.

In the CAISO's Market, a Wheeling Out transaction consists of an Export Bid or Demand Bid for a transaction that leaves the ISO Controlled Grid (both inside and outside the Balancing Authority).   The Export Bid or Demand Bid may be in the form of a Self-Schedule and/or an Economic Bid.

In the CAISO's market, a Wheeling Through transaction consists of an Import Bid and an Export Bid with the same Wheeling reference. The Export/Import Bids may be in the form of a Self-Schedule and/or an Economic Bid. A Wheeling Through transaction is identified with a unique wheeling reference ID which is registered in the CAISO Master File. The Wheeling Through transaction can be specified between any two Scheduling Points in the system. The schedules of the import and export resources in a Wheeling Through transaction are kept balanced in the SCUC co-optimization engine. Any Self-Schedules can be uneconomically adjusted respecting assigned priorities as described in CAISO Tariff Sections 31.4 and 34.10. An ~~E tag~~E-Tag or ~~E tag~~E-Tags for a Wheeling Through transaction must reflect a resource outside of the CAISO Controlled Grid as the source of the transaction. An ~~E tag~~E-Tag or ~~E tag~~E-Tags for a Wheeling Through transaction that leaves the ISO Balancing Authority Area must reflect a sink outside of the CAISO Controlled Grid.

Wheeling Through is associated with the entire Energy Bid, i.e., both the Self-Schedule quantity and the Economic Bid price curve. The balancing of wheeling energy is enforced by the constraint:

Total export MW schedule = Total import MW schedule

This constraint is enforced for each wheeling pair and each time interval in the MPM, IFM, and RTM.

Wheeling Through transactions will be ignored in RUC, since the Day-Ahead Schedule for Energy (i.e., the IFM Energy Schedules), which includes the Wheeling Through transactions are fixed at the IFM Energy Schedule quantities. These IFM Energy Schedules receive a higher priority with respect to RUC Availability Bids in meeting CFCD. Therefore, energy flows due to wheeling transactions that clear the IFM are included in the RUC optimal solution. RUC may back down IFM Energy Schedules to Minimum Load to achieve a solution. However, these adjustments are not subject to Settlements implications. Because there is no actual Energy delivered with a Wheel Through, the import side of a Wheel Through is not eligible for Energy Bid Cost Recovery.

2.5.2.3   Self-Provided Ancillary Services

Participating Generators and Participating Loads certified for AS may self-provide those AS in the DAM/RTM. PDRs may self-provide non-spinning reserve only in DAM/RTM. A Submission to Self-Provide AS in a given Trading Hour contains only a capacity offer without a price. Submissions to Self-Provide an AS are evaluated for feasibility with respect to the relevant resource operating characteristics and regional constraints, and are then qualified (accepted) prior to AS Bid evaluation. If a regional constraint imposes a limit on the total amount of Regulation Up, Spinning Reserve, and Non-Spinning Reserve, the Submissions to Self-Provide AS in that region may be limited, and are qualified pro rata in the following order:

➢ Regulation Up
➢ Spinning Reserve
➢ Non-Spinning Reserve

The process for qualifying the Submissions to Self-Provide AS is described in more detail in Section 4.2.14.2.14.2.1. Once qualified, the Submissions to Self-Provide AS are considered Self-Provided AS, i.e., a qualified Self-Provision of AS. Self-Provided AS effectively reduces the AS requirements that need to be met by AS Bids. Self-Provided AS also reduces the AS Obligation in the AS Bid Cost allocation for the SC that Self-Provided the AS.

Qualification of Self-Provided AS indicates self-commitment [11] except for Non-Spinning Reserve Self-Provision from offline Fast-Start Units.

PSHUs and hydro pumps may Bid or Self- Provide Non-Spinning Reserve in pumping mode up to the Pumping Level if they do not self-schedule in pumping or generating mode. Except for

---

[11] If the unit is committed in the IFM (DA) and the SC subsequently Self-Provides AS, e.g., in the RTM process, the RTM Self-Schedule is not considered a self-commitment.

System Resources associated with ETC/TORs, System Resources may not Self-Provide AS (they can only submit Economic Bids for AS) because the DAM/RTM applications reserve transmission capacity for AS imports on Interties, which takes place in the optimization. The qualification process for AS Self-Provision is a pre-processing that could inevitably provide higher scheduling priority to Self-Provided AS over TOR/ETC Self-Schedules.

Refer to Section 4.2.1, Self-Provided Ancillary Services, and Section 4.2.2, Conversion of Ancillary Services to Energy in DAM, for information on qualifications of Ancillary Services with respect to RA resources.

System Resources providing A/S must be certified for AS and must be capable of providing Energy in Real-Time.

2.5.2.4   Virtual Bids

"Convergence" or Virtual Bids are financial bids submitted only in the Day-Ahead Market. The Integrated Forward Market (IFM) clears Virtual and physical Bids in a non-discriminatory manner. If cleared in the IFM, the resulting Virtual Supply and Virtual Demand Awards would settle first at the locational Day-Ahead LMP and then be automatically liquidated with the opposite sell/buy position at the simple average of the four applicable FMM LMPs.

Convergence bidding provides Market Participants with several financial functions. First, there is the opportunity to earn revenues (and to risk losses) resulting from any differences in the Day-Ahead and FMM LMPs. Market Participants, using their insights into system and market conditions, may be able to identify Virtual Bidding opportunities that result in more efficient market outcomes. The potential for financial reward encourages Virtual Bidding activity that would tend to minimize any systematic differences between Day-Ahead and FMM LMPs, thus minimizing incentives for under or over-scheduling physical Demand in the Day-Ahead Market. A generator owner can also use a Virtual Bid to mitigate the risk impact of an outage that happens after the close of the Day-Ahead Market. By increasing market liquidity through Virtual Bidding, the potential for the exercise of market power also decreases.

Virtual Bids are explicitly flagged as Virtual Bids when submitted to the Day-Ahead Market. Their submission and processing includes an indicator that identifies them as Virtual Bids rather than physical Bids. This indication:

1) Aallows for their exclusion from the automated Local Market Power Mitigation process;

2) allowsAllows the Virtual Bids to be tracked and associated with the Convergence Bidding Entity;

3) ~~allows~~Allows the CAISO to be able to suspend Virtual Bids by location or by Convergence Bidding Entity when necessary[12]; and

 4~~5~~4) ~~allows~~Allows the CAISO to exclude Virtual Bids from the RUC market.

2.5.2.4.1   Eligible Bidding Locations and Position Limits

Virtual Bids may only be submitted at certain locations. The Eligible PNode and Eligible Aggregated PNode locations may include:

- Internal Nodes (Generator and/or Load)
- Points-of-Delivery (POD)
- Trading Hubs
- DLAPs (excludes CLAPs and MLAPs)
- Intertie Scheduling Points (Imports/Exports) except for locations where either the Operating Transfer Capacity or Available Transmission Capacity is zero

Locations that are eligible for Virtual Bid submission, except for DLAP's and Trading Hubs, are subject to Position Limits (or maximum MW Bid amounts) being enforced for those Virtual Bids submitted by SC on behalf of a single Convergence Bidding Entity (CBE). Limits are defined in the Master File by location type as specific percentages of the absolute maximum MW amount of the physical resource connected to the Eligible PNode or Eligible Aggregated PNode.

Position Limits for eligible physical supply Pnode locations will be based on the PMax of the physical resource as defined in the Master File, if the PNode is associated with a single physical supply resource, and the sum of the PMaxs of the physical supply resources as defined in the Master File, if the PNode is associated with more than one physical supply resource. Position Limits for eligible physical Demand locations will be based on the forecast of the maximum MW consumption of the physical Demand resource, if the PNode is associated with a single physical Demand resource, and the sum of the forecast of the maximum MW consumption of the physical Demand resources, if the PNode is associated with more than one physical Demand resources.

In the case where both physical supply and physical Demand resources are connected to an Eligible PNode or Eligible Aggregated PNode within the CAISO Balancing Authority Area, the greater of the two resources (either supply or Demand) is used as the basis for calculating the applicable Position Limit. Position Limits for Scheduling Point locations will be based on the published Intertie's Total Transfer Capability (TTC) and the CAISO will enforce Position Limits

---

[12] The CASO has the authority to suspend or limit Virtual Bids pursuant to Tariff Sections 7.7.15. and 7.9.

using the 9:00 AM TTC for Virtual Bids submitted after 9:00 AM until the close of the Day-Ahead Market for the next Trading Day.

Refer to Tariff sections 30.7.3.6.3 for information on Position Limit settings.

CAISO will report the Eligible PNode and Eligible Aggregated PNode locations and their maximum MW limits in OASIS. Please refer to the *BPM for Market Instruments* for additional information.

2.5.3   Inter-SC Trades

CAISO facilitates Inter-SC Trades (IST) of Energy, Ancillary Services and IFM Load Uplift Obligation through the Settlement process. There are two types of IST of Energy. Physical Trades (PHY) which are ISTs at individual PNodes of Generating Units within the CAISO Balancing Authority Area that are backed by a physical resource at that Location and Inter-SC Trades at Aggregated Pricing Nodes (IST APN), which do not require the SC to identify the specific physical resource that is backing the trade. Each AS can be traded through IST as can the IFM Load uplift obligation. Inter-SC Trades are financial and do not have any physical impact on the market optimization solution. They are further described in Section 9 of the *BPM for Market Instruments*.

2.5.4   Existing Transmission Contracts, Transmission Owner Rights, & Converted Rights

Existing Transmission Contracts, Transmission Owner Rights, and Converted Rights are described in Section 5 of this BPM.

2.5.5 Use-Limited Resources

Since the nature of Use-Limited Resources prevents them from being available every hour of every day, Use-Limited Resources are subject to supplemental rules and guidelines.

The CAISO Tariff refers to two distinct processes applicable for Use-Limited Resources:

1. Application to Register Use-Limited Resources as specified in CAISO Tariff Section 40.6.4.1.

2. Submission of Use Plans as specified in CAISO Tariff Section 40..6.4.2.

2.5.5.1   Use-Limited Resource Registration

CAISO Tariff Section 40.6.4.1

For a resource to be considered a Use-Limited Resource, the Scheduling Coordinator must provide the CAISO with a request to register the specifically identified eligible resource as a Use-Limited Resource along with appropriate supporting documentation as noted below.

Hydroelectric Generating Units, Participating Load, Pumping Load, PDR, and RDRR are exempt from the requirement to register as a Use-Limited Resource and will be automatically designated by the CAISO as a Use-Limited Resource. However, even though the CAISO will designate these types of resources as use limited, there is a documentation requirement for hydro resources which is noted below.

To request the CAISO to register an eligible resource as a Use-Limited Resource, the Scheduling Coordinator should open an Inquiry Ticket via the Customer Inquiry Dispute and Information (CIDI tool.   The ticket must include specific operating data for the unit and supporting documentation including, but not limited to:

- A detailed explanation of why the unit is subject to operating limitations.

- Documentation, such as environmental permits or operating manuals, as well as page numbers or section numbers in the supporting documentation, substantiating the detailed explanation of why the unit is subject to operating limitations.

- Historical data showing attainable MWh for each 24-hour period during the preceding year. Data should include environmental restrictions and other factors as applicable.
- Any additional data in order for CAISO to understand the operating characteristics of the unit.

Although the CAISO intends to review applications individually, the following table provides general non-binding guidelines regarding the scope of Use-Limited status. The definition of a Use-Limited Resource is "a resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day." Note that under the CAISO tariff, contractual limitations on the availability of Resource Adequacy resources, do not qualify a resource for Use-Limited status.

Upon submission of the required information in the CIDI Ticket, the scheduling coordinator must then submit an updated resource data template (RDT) through the master file. The CAISO will review the information provided and either approve or deny the RDT submission as appropriate. If additional information is required, the CAISO will request such information through the CIDI

ticket. If the RDT submission is ultimately denied, the CAISO will provide an explanation for the denial. If the RDT submission for Use-Limited status is approved by the CAISO, scheduling coordinators can then submit the use limit plan data template through master file along with supporting documentation through CIDI as described in section 2.5.5.2 below.

Use-Limited Resource registration can occur at any time. Within five business days of the receipt of the request, the CAISO will respond to the Scheduling Coordinator as to whether or not the ISO agrees that the resource is eligible to be a Use-Limited Resource. If the CAISO does not have sufficient information to make this determination, it will also notify the Scheduling Coordinator that additional information is needed. Once the CAISO receives additional information, a new five business day timeline will be established. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

Resource-Type	Use-Limited (Yes/No)	Supporting Documentation Requirement in CIDI
Gas-Fired (Steam)	No	No
Gas-Fired (Combined Cycle)	No	No
Gas-Fired (GT with limited fuel storage)	Yes	Limitation -Air Permit Translation/Formula - As Required
Gas-Fired (GT without limited fuel storage)	No	No
Gas-Fired with environmental restrictions that constraint its operation	Yes	Limitation -Air Permit Translation/Formula - As Required
Hydro-Large Storage	Yes/No - although Hydro with large amount of storage may have more flexibility to generate on demand and thus may not be use-limited in a manner similar to a run-	Limitation - Storage Translation/Formula - ERRA Summary

	of-the river, downstream water flow and water-release needs and other environmental conditions may dictate output so as to warrant Use-Limited status	

Hydro-Small Storage/Small Conduit	Yes	Limitation
		  - Storage Translation/Formula
		  - ERRA Summary

Hydro-Run of the River	Yes	Limitation
		  - Storage Translation/Formula
		  - ERRA Summary

Wind	Yes	No
QF Resource and Must Take	Yes	No

QF Resource and not Must Take	Yes	Limitation
		  -Air Permit Translation/Formula
		  - As Required

Solar	Yes	No
Nuclear	Yes	No

The CAISO may allow a Resource Adequacy Resource that is subject to temporary or seasonal environmental restrictions imposed by federal or state law or regulation to be designated as a Use-Limited Resource for the period in which the restriction applies. Temporary environmental Use-Limited Resource status will begin on the start date of the restriction and end on the end date of the restriction, and may include a partial month or full month for Resource Adequacy purposes. A Resource Adequacy Resource may request temporary environmental Use-Limited Resource status by submitting the request required by this section including a detailed explanation of the temporary or seasonal environmental restriction that is the basis for its request. As with annual Use-Limited Resource status, a contractual limitation or economic reason will not qualify a Resource Adequacy Resource for temporary environmental Use-Limited Resource status.

2.5.5.2   Use-Limit plan data template (ULPDT)

CAISO Tariff Section 40.6.4.2

The CAISO will only accept a ULPDT for a resource where a Scheduling Coordinator has successfully registered it as a Use-Limited Resource and/or properly maintained its Use-Limited Status.

The documentation column of the ULPDT must specify the CIDI ticket number through which the use limit documentation was provided to the CAISO, and must include the document name and relevant page numbers where the limitation may be found.[13] If the ULPDT does not specify the CIDI ticket number, then the template will be rejected by the CAISO. If no supporting documentation is required, state "not required" in the documentation column. The effective date of the ULPDT has to be five business days out from the day of submission.

The Scheduling Coordinator provides a proposed annual use plan for the following year for each Use-Limited Resource. The proposed annual use plan delineates the total MWhs of Generation, total run hours, expected daily supply capability (if greater than four hours) and the daily energy limit. The CAISO may discuss the proposed annual use plan with the Scheduling Coordinator and suggest potential revisions to meet reliability needs of the system. If revisions are agreed upon, the Scheduling Coordinator then submits its final annual use plan for the coming trade year by the last business day of October of the year before the intended use of the annual use plan. The Scheduling Coordinator is able to update the projections made in the annual use plan in optional monthly updates to the annual use plans. The monthly updates are required to be submitted at least 5 business days prior to start of the compliance month. Intra-Month ULPDT updates for a given month are allowed only for Hydroelectric Generating Units and Pumping Load where the updated ULPDT must have an effective date five business days out from the date of submission to the master file.

If the nature of the use limitation (*e.g.*, the environmental or operational restrictions initially justifying Use-Limited status) has changed intra-year, then the Scheduling Coordinator must reflect the changed limitations in monthly updates.

---

[13] For resources that were granted status as a Use-Limited Resource before the CAISO required the use limit documentation to be submitted to CIDI as part of the initial application, the documentation must be submitted in a new CIDI ticket either before, or concurrent with, submission of the first use plan that utilizes the ULPDT.

Scheduling Coordinators for hydroelectric Generating Units will be able to update use plans intra-monthly as necessary to reflect evolving hydrological and meteorological conditions. Resources that are approved for temporary environmental Use-Limited Resource status must submit a use plan that reflects the time-limited nature of the use-limited status. Such resources will not be considered as Use-Limited Resources during the balance of the year.

The CAISO considers all Resource Adequacy Use-Limited Resources as available 24 hours per day, 7 days per week unless the CAISO receives a valid annual or updated monthly plan that indicates the resource's use-limitations for the trade month. Once the CAISO receives a valid annual use plan or updated monthly use plan, the CAISO will apply the use-limitations indicated in that use plan for the time period(s) shown in that use plan.

The use plan is information provided to the CAISO to better plan out its operations – it is not intended to affect an LSE's ability to count a Resource Adequacy Resource or serve as a basis for Sanctions. However, the use plans should be consistent with the minimum counting criteria established by the CPUC or Local Regulatory Authority. If the use plan does not meet the minimum criteria, the CAISO would confer with the CPUC or Local Regulatory Authority regarding the suitability of such a resource as being offered as a Resource Adequacy resource.

Note: All Use-Limited Resources remain subject to operating in System Emergency conditions to the extent that a Participating Generator Agreement has been executed for the resource.

Information on use plans and a template for such plans can be found at:

http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx

Maintaining Use-Limited Status

For trade year 2016 and each year thereafter, if the nature of the use limitation (*e.g.*, the environmental or operational restrictions initially justifying Use-Limited status) has changed since the resource first was granted Use-Limited status or since the nature of the use limitation last changed, then the Scheduling Coordinator must submit updated documentation substantiating the resource's Use-Limited status. Scheduling Coordinators must submit required information to customer inquiry dispute and information tool found on market participant portal. In the subject line of the ticket please specify if the documentation is for ULR renewal of the use limitation status or ULR registration for a new resource. If supporting documentation has changed then scheduling coordinators are required to resubmit the use plan data template through the master file.

3.   Full Network Model

Welcome to the *Full Network Model* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

➢ A description of the models and terminology that are used to coordinate the Full Network Model (FNM) with the CAISO Markets

➢ The FNM is discussed from the market operations perspective

The *BPM for Managing Full Network Model* provides further details, including the relationship between the reliability model and the network model, the base case, the AC solution, and the CRRs. Remedial Action Schemes (RAS)[14] are also described in the BPM.

3.1   Model Description

FNM is comprised of a detailed model of the physical power system network along with an accurate model of commercial network arrangements. These arrangements reflect the commercial scheduling and operational practices to ensure that the resulting LMPs reflect both the physical system and the schedules produced by the market applications.

The CAISO markets employ a FNM with an accurate representation of the CAISO Balancing Authority Area and embedded and adjacent Balancing Authority Areas. The CAISO enforces both scheduling and physical constraints at each CAISO Intertie to reflect:

a) The scheduling constraint that constrains the physical Energy and Ancillary Services Bids from scheduling hubs when these Bids declare the respective Intertie for schedule tagging; there are no shift factors used in these constraints. Both physical and Virtual Bids will be considered in this constraint in the Integrated Forward Market. Only physical schedules will be considered in the Residual Unit Commitment.

b) The physical flow constraint that constrains the schedule contributions from all physical and Virtual Energy Bids inside and outside of the CAISO Controlled Grid; shift factors are used in these constraints. Both physical and Virtual Bids will be considered in this constraint in the Integrated Forward Market. Only physical schedules will be considered in the Residual Unit Commitment. The scheduling and physical constraints are limited by the same operational limit of the Intertie.

The FNM is composed of network Nodes[15] (henceforth CNodes) interconnected with network branches. Generating Units and Loads are modeled at the relevant CNodes. A subset of CNodes is selected to be Pricing Locations (PNodes).

---

[14] RAS are implemented to maintain system reliability and are not managed as part of the market optimization. To the extent that RAS operations affect transmission constraints, the corresponding limits are enforced by the market applications.

A PNode is identified as a CNode at which LMPs are calculated, i.e, for each resource and substation. Each PNode is associated with a single CNode in the network model. As used in the Reference Data Requirements documentation on the CAISO website, CAISO has groupings of CNodes that are used in the running of the CAISO Markets, including the CAISO system, Balancing Authority Areas, RUC zones, and Load forecast zones. This is different than the Aggregated Pricing Nodes (APNodes, which are groupings of PNodes used to consolidate the bidding and pricing of physical and Virtual Supply and Demand in the CAISO Markets).

Import and export resources are modeled as System Resources at the CNodes at the external end of interties with other Balancing Authority Areas (i.e. Scheduling Points). Aggregate Generating Units and Loads are modeled as individual physical resources in the FNM, and their Energy Supply and Demand is then mapped to their associated physical resources in the FNM using the relevant Generation and Load Distribution Factors, respectively.

For the IFM only, Virtual Awards are modeled as new objects dynamically created internal to the power flow application. These new objects are referred to as virtual injections. These virtual injections are created at all locations where there are Virtual Awards, whether or not physical Supply or physical Demand objects exist at these locations. In the case where Virtual Awards are co-located with physical Demand or Generation, the virtual injection will be a separate object and the MW value of the virtual injection will not be mapped to the MW value of the physical injection.

To the extent sufficient data is available or adequate estimates can be made for the Integrated Balancing Authority Areas, the CAISO may use this data for power flow calculations and Congestion Management in the CAISO Markets Processes. CAISO monitors but does not enforce the network constraints for Integrated Balancing Authority Areas in running the CAISO Markets Processes. CAISO models the resistive component for Transmission Losses on Integrated Balancing Authority Areas but does not allow such losses to determine LMPs.

The use of the FNM in the DAM and the RTM incorporates Transmission Losses and allows modeling and enforcing all network constraints. This results in LMPs for Energy that reflects the System Marginal Energy Cost (SMEC), Marginal Cost of Losses (MCL), and Marginal Cost of Congestion (MCC). Although the SMEC component of the LMP is the same for all PNodes, based on the selection of a certain Reference Bus, the MCL and the MCC may vary across the network due to network characteristics and power flow patterns.

---

[15] The CAISO BPMs have adopted "Connectivity Node" or CNode as an alternative expression of "Node". Aggregated PNodes are also referred to as "APNodes".

3.1.1   Real-Time Data

The following Real-Time data are passed from the Energy Management System (EMS) and the State Estimator (SE) to the Real-Time Market (RTM):

Exhibit 3-1: Generator Telemetry Data from EMS to RTM

Variable	Comment
Unit ID	Generating Unit Identification
Unit Telemetry	Actual MW amount of Power produced
Reg Flag	Unit's Regulation Status (Y = Active) (N = Not Active)
Max Op Limit	Maximum Operating Limit [MW]
Min Op Limit	Minimum Operating Limit [MW]
Unit Online	Unit's Online Status (Y = On Line) (N = Off Line)
Quality Tag	Unit's Data Quality (1 = Good) (2 = Bad) (3 = Manual Override)

Exhibit 3-2: Load Telemetry Data from EMS to RTM

Variable	Comment
Load ID	Load Identification
Load Telemetry	Actual MW amount of Power consumed
Quality Tag	Load's Data Quality (1 = Good) (2 = Bad) (3 = Manual Override)

Exhibit 3-3: Connectivity Node Data from SE to RTM

Variable	Comment
CNode ID	Connectivity Node Identification (Load or Generator)
MW Level	State Estimator MW (Load or Generator)
Connection	"C" for Connectivity

3.1.2   Generation Distribution Factors

SCs may submit single Bids for multiple Generating Units at an APNode (Physical Scheduling Plant and System Unit) or individual Bids for individual Generating Units at individual PNodes, depending on how the Generating Units are registered with CAISO. An APNode is associated with a designated set of PNodes. Supply Bids and Self-Schedules that are submitted for the Aggregate Generating Resource at an APNode are distributed by CAISO to the associated individual PNodes according to a set of Generation Distribution Factors (GDFs), consisting of factors and location names that must also be submitted with the Bid. These GDFs are

automatically re-normalized in the CAISO Market applications to account for any Generating Unit Outages.

SCs may provide GDFs for its Aggregate Generating Resources with its bid, otherwise the Market Applications will use default GDFs from the GDF Library. The submitted GDFs should reflect actual conditions and should be submitted as normalized values (summing up to 1.0).

Aggregated Generating Resources must be registered and approved by CAISO. CAISO evaluates the extent to which the individual resources share a common fuel supply and how they are physically located on the grid. The evaluation of whether a generator is allowed to be part of an Aggregate Generating Resource is generally performed during the CAISO's generator interconnection process. Refer to CAISO website for details:

http://www.caiso.com/docs/2002/06/11/2002061110300427214.html

The CAISO Market applications optimally commit and schedule Aggregate Generating Resources based on their aggregate Bids and their aggregate location. The aggregate schedules are decomposed using the relevant GDFs to individual physical unit schedules for power flow calculations in the Full Network Model.

Virtual Supply Bids at the Aggregated PNode locations will have the GDF applied just as physical Supply Bids thereby treating physical and Virtual Bids consistently in the Day-Ahead Market.

The LMP for an Aggregate Generating Resource is calculated after Market Clearing as the weighted average of the LMPs at the PNodes associated with the individual Generating Units comprising the Aggregate Generating Resource, using the relevant GDFs as the weighting factors.

3.1.3   Modeling Point

Exhibit 3-5 illustrates another type of APNode, where the model consists of one or more Generating Units supplying Power to the CAISO markets.

The Point of Receipt of a Generating Unit is established by technical information provided by the Generator and Transmission Owner during the CAISO's Generation interconnection process or based on existing information. The Point of Receipt may be different from the physical location (CNode) where the Generating Unit is connected. The FNM represents the Generating Unit at its actual physical location, and computes loss factors from that location to the contractual Point

of Receipt. Settlement is based on deliveries to the Generating Unit's Point of Receipt, and uses the LMP at such point.

In general, the pricing Location of a Generating Unit coincides with the CNode where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Units are connected to the CAISO Controlled Grid. This Location is referred to as the PNode. Although the schedule, Dispatch, and LMP of a Generating Unit refers to the PNode, the Energy injection is modeled in the FNM for network analysis purposes at the corresponding Generating Unit(s) (at the physical interconnection point), taking into account any losses in the transmission network leading to the point where Energy is delivered to Demand.

3.1.4   Load Distribution Factors

SCs must submit Bids for Non-Participating Load resources at an aggregate location (ANode). The IFM optimally schedules Non-Participating Load based on its aggregate Bid at the corresponding ANode. The aggregate Load schedule is decomposed using the relevant LDFs to individual physical Load schedules for power flow calculations in the Full Network Model. MPM, RUC and RTM also use LDFs to decompose the CAISO Forecast of CAISO Demand (CFCD) for power flow calculations in the Full Network Model. These LDFs always sum up to 1.0 for a given aggregation.

If there is a Virtual Supply Bid or Virtual Demand Bid at the Default LAP location, the Default LAP LDF will be applied to the Virtual Bid in the same way as the physical Demand Bid, thereby treating physical and Virtual Bids consistently in the Day-Ahead Market. Default LAP LDF's will not be affected by Virtual Supply Bids or Virtual Demand Bids at an individual node. Default LAP LDF's are based on physical load.

CAISO maintains a library of LDFs for use in distributing Load Aggregate schedules at Default or Custom LAPs in IFM and the CFCD in MPM and RUC. These LDFs are derived from the EMS State Estimator (SE) and are stored in the LDF Library. The LDF Library gets feeds from the SE, and keeps a historical average of LDFs for different system conditions. For RTM, the SE solution is used directly as the source of LDFs. For DAM, the appropriate LDFs are used from the LDF Library. The LDF Library produces historical average LDFs based on a similar-day methodology that uses data separately for each day of the week and holidays, rather than for weather conditions. More recent days are weighted more heavily in the smoothing calculations. The ISO may adjust load distribution factors prior to use by the market application to reflect weather conditions expected in the market time horizon.

CAISO also maintains a set of Load Aggregation Factors (LAFs) in the Master File for each Default or Custom LAP. These LAFs represent the percentage sharing of load at the CNode among different overlapping LAPs.

The CAISO Market applications then use the set of LDFs from the library that best represents the Load distribution conditions expected for the market Time Horizon. If LDFs are not available in the LDF Library, static LDFs can be loaded into the system.

The Energy Settlement for Non-Participating Load resources is at the corresponding Aggregate LMP. That Aggregate LMP is calculated after Market Clearing as the weighted average of the LMPs at the individual load locations (CNodes). The weights in the Aggregate LMP calculation are the relevant LDFs.

Exhibit 3-4 illustrates the model of a LAP.

Exhibit 3-4: Load Aggregation Point
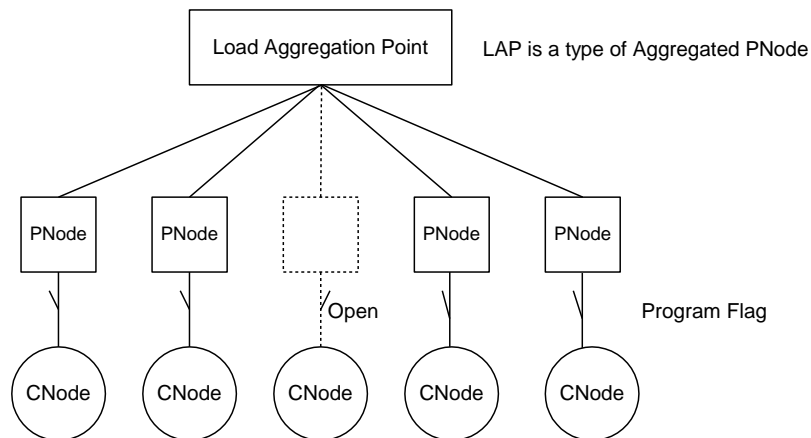
CNode = Connectivity Node
PNode = Pricing Node

Exhibit 3-5: Modeling Point
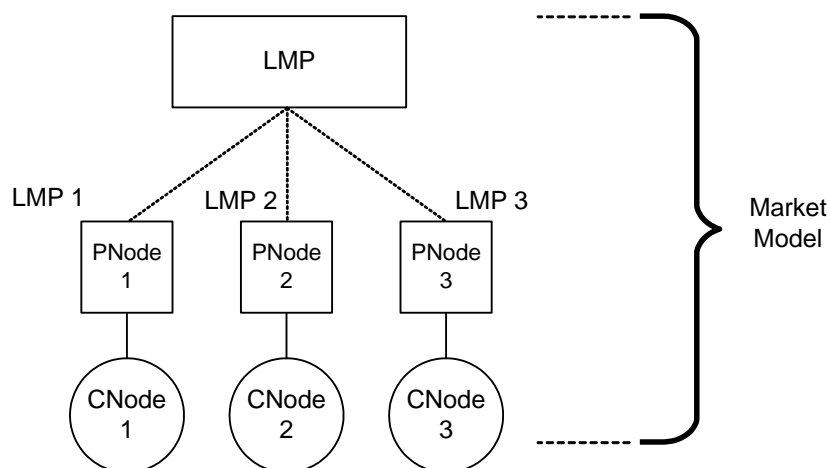
3.1.5   Aggregated Pricing Nodes

Aggregated Pricing Nodes (APNodes) are aggregations of Pricing Nodes as defined by CAISO which include LAPs and Trading Hubs.

The CAISO Market applications calculate LMPs and their components for all PNodes and APNodes, and all resources, including aggregate resources. The LMP of a resource is the LMP of the corresponding Location, aggregate or not. LMPs for Aggregate Generating Resources and aggregate Non-Participating Loads are calculated as weighted averages of the LMPs at the relevant PNodes, weighted by the relevant GDFs and LDFs. Note that since the distribution of the aggregate Energy schedules for aggregate resources is fixed and based on the relevant GDFs and LDFs, the weights are also equal to the relevant normalized individual Energy Schedules for these resources. For Default LAPs the prices are derived directly from the optimization based on the effectiveness of the total aggregation on reliving congestion, within the effectiveness threshold specified in section 6.6.5.

Aggregate LMPs are also calculated for Trading Hubs, which are defined as APnodes. Trading Hub LMPs are used for the Settlement of CRRs and Inter-SC Trades of Energy, other than physical Inter-SC Trades of Energy. The weights applied to the constituent nodal LMPs in each Existing Zone Generation Trading Hub are determined annually and separately for each season and on-peak and off-peak period based on the ratio of the prior year's total output of Energy at that PNode to the total Generation output in that Existing Zone, for the corresponding season and on-peak or off-peak period. Trading Hub prices are derived directly from the optimization based on the effectiveness of the resource as an aggregate if the effectiveness of the aggregate resource is at or above the effectiveness threshold specified in section 6.6.5.

The CAISO Market applications also calculate the Shadow Prices of all binding network constraints and scheduling constraints at the optimal solution. The Shadow Prices contribute to the Marginal Cost of Congestion component of the LMPs. Furthermore, the Shadow Prices at Scheduling Points are used in used in Settlement to calculate explicit Congestion charges to Ancillary Services Imports.

3.1.6   Losses

There are two types of losses:

  ➢ **Transmission Losses** – also referred to as actual losses
  ➢ **Marginal Losses** – also referred to as incremental losses

Both actual and Marginal Losses are generally higher when Generation or imports are far away from CAISO's major Load centers and losses are lower when Generation is close to the Load centers. Both the actual MW losses and the Marginal Losses depend on the resistance of branches in the network, which depends in turn on factors including the length and conductor type of transmission lines, and transformer characteristics, and the MW loading and voltage profile of the Transmission network.

3.1.6.1   Transmission Losses

Transmission Losses are the Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered by CAISO at the UDC, MSS, or Balancing Authority Area boundary.

For example, if the total Power delivered to all the boundaries is 20,000 MW and the total CAISO Generation is 20,200 MW, then the Transmission Losses equal to 20,200 MW minus 20,000 MW or 200 MW.

The FNM is an AC network model that includes the effect of Transmission Losses within the CAISO Balancing Authority Area. The SCUC/SCED applications optimally adjust resource Schedules to cover Transmission Losses. In other words, the final CAISO Market Energy Schedules for Supply exceeds the corresponding Energy schedules for Demand and exports by the amount of Transmission Losses in the CAISO Balancing Authority Area.

Exhibit 3-6 shows the Power balance relationship for the CAISO Balancing Authority Area and illustrates the above Transmission Losses example. In the IFM, Virtual Demand and Supply Awards are included in the Power balance equation.

Exhibit 3-6: CAISO Power Balance Relationship
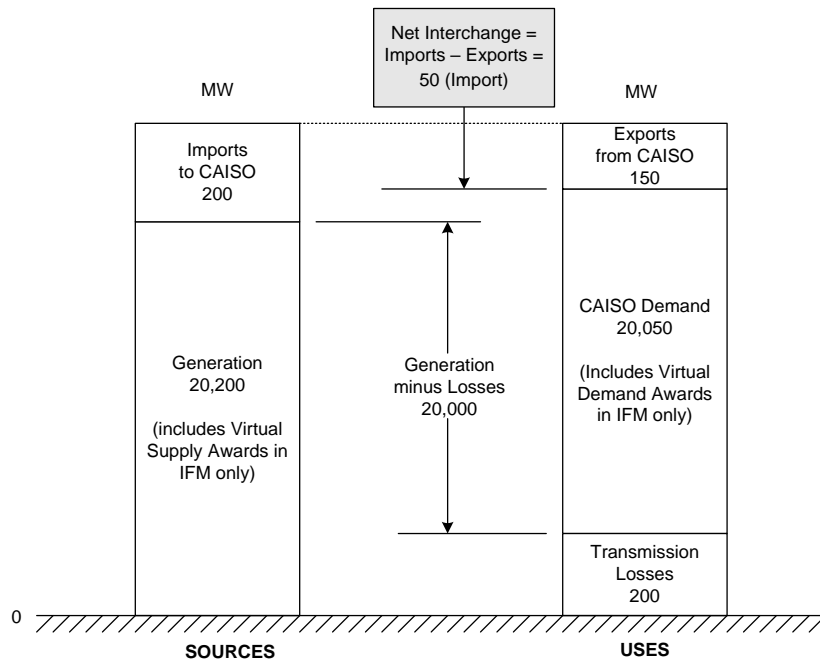
For the Non-Participating Transmission Owner (NPTO) network, transmission losses will be calculated and assessed based on governing contractual arrangements if any exist, or any Transmission Ownership Rights contractual arrangements presented to the CAISO and the location of the Energy injection.

3.1.6.2   Marginal Losses

Marginal Losses are the transmission system incremental real power losses that arise from changes in Demand at a CNode that is served by changes in is the distributed Load reference as further described in the *BPM for Managing Full Network Model*.

For example, if we increase the Demand by 1.0 MW at CNode X and observe that the distributed Load reference must increase its output by 1.1 MW to serve this Demand increase, then the Marginal Losses with respect to CNode X is equal to 1.1 MW minus 1.0 MW or 0.1 MW.

The corresponding Marginal Loss Factor for CNode X is equal to the Marginal Losses for Node X divided by the increase in Demand at CNode X, in this example (0.1 MW / 1.0 MW = 0.1).

These Marginal Loss Factors are used in the calculation of LMPs and they are determined by sensitivity analysis on the AC power flow solution. The Marginal Cost of loss component is equal to the marginal loss factor multiplied by the System Marginal Cost of Energy.

Exhibit 3-7 illustrates the definition of Marginal Losses with respect to the distributed Load reference in the CAISO Balancing Authority Area. Depending on the CNode locations, the system-wide Transmission Losses may either increase or decrease (slightly) as the Load at the CNode is increased by a small amount.

Exhibit 3-7: Marginal Losses - Conceptual Model

Marginal Loss Factors are calculated using AC power flow calculations during each market

All Buses with attached Load
(i = 1 to N)

Marginal
Losses

$Load_1$

$Load_2$

Cnode
Bus_n

Pseudo

Gen

$Load_i$

ΔG_n

ΔD_i

$Load_{N-1}$

ΔL_n

$Load_N$

$$\Delta D_i = \frac{Load_i}{Total\ Load}$$

$$\Delta G_n = 1 + \Delta L_n$$

$$\sum \Delta D_i = 1\ MW$$

MW

CAISO
Transmission
Losses

Operating
Point

Positive Marginal Loss
(Increasing Transmission Losses)

Negative Marginal Loss
(Decreasing Transmission Losses)

0

MW

Load
@ CNode
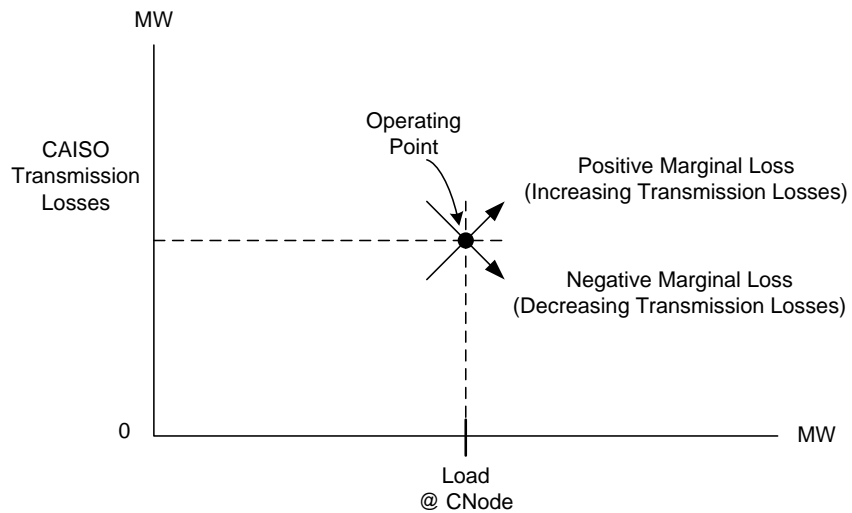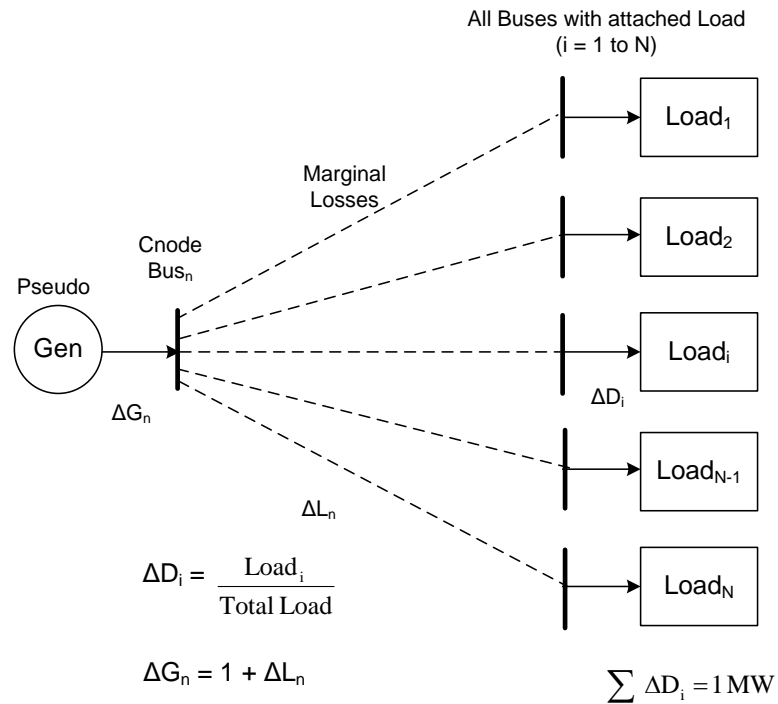
Note 1: The "upward" or "downward" direction of the
curve depends on the choice of Reference Bus

Note 2: The operating point is independent of the
choice of Reference Bus

solution. Thus, they are dynamic factors that change for each Trading Hour in the DAM and each 15 minute interval in the RTM.

Marginal Loss Factors are not expressly published by CAISO, but they can be calculated from the published components of LMP.

The actual MW losses are used in parts of Settlement such as UFE, but are not part of the LMP calculation – the LMP reflects the rate of change in losses, not the total MW lost.

The CAISO Energy Settlement process includes settlement of the marginal cost of losses through the Marginal Cost Component of the LMP. Because Marginal Losses are higher than actual losses (almost by a factor of 2), the LMP settlement results in loss over collection. CAISO distributes the surplus losses to Scheduling Coordinators through the allocation of the IFM Marginal Losses Surplus Credit as explained in CAISO Tariff Section 11.2.1.6, or for the Real-Time Market, through its Neutrality Adjustments in CAISO Tariff Section 11.14. More details are in the *BPM for Settlements and Billing, Section 11.4.*

CAISO excludes the Marginal Cost of Losses on branches that are within embedded and adjacent Balancing Authority Areas, Metered Subsystems which do load following, and PTO networks that are outside the CAISO Balancing Authority Area.

CAISO calculates actual MW losses in these areas to maintain consistency with the State Estimator's power flow solution, and the MW losses affect the balance of Supply and Demand. However, the actual MW losses in these areas are reported separately for Unaccounted for Energy (UFE) calculations as well as being excluded from LMP calculations.

3.1.7   Nomograms

A Nomogram is used to define a constraint relationship between two power system MW variables. Exhibit 3-8 illustrates a Nomogram where the vertical axis represents the constraint and the horizontal axis represents the independent variable. Typical Nomograms are for the following, where the first mentioned name is the constrained variable and the second mentioned name is the independent variable:

> ➢ AC interface MW flow versus AC interface MW flow
> ➢ AC interface MW flow versus area MW Generation

CAISO derived Nomograms are based on network analysis and reliability studies. CAISO maintains a library of Nomogram definitions and associated parameters, which is maintained by CAISO Regional Transmission Engineers to reflect current power system conditions. The

market applications retrieve the active Nomogram definitions and incorporate them into the market optimization constraints such that the end result is to Re-dispatch Generation to satisfy the Nomogram constraints by staying within the enclosed region.

It should be emphasized that Nomograms can be used to not only restrict the flow of Power over the transmission network, but can also be used to restrict the flow of area interchange or area Generation.

To be modeled in the market software, which uses quadratic optimization – a Nomogram must be piecewise-linear and convex. Where this is not the case, the Nomograms need to be enforced in other ways. For some cases, the Nomogram limits are based on specific contingencies, and CAISO can include the same contingencies in the market runs. Each market has the capability of modeling contingencies, and including these contingencies gives the same outcome as if CAISO had modeled them as Nomogram limits.

If Outages already exist on related network branches, then the result of the Contingency is more restrictive than the original Nomogram limit, which is the result of more reliable system operation.

Complex Nomograms are part of some operating procedures, and some of these may be more difficult to include in the market software. In these cases CAISO enforces the Nomograms through monitoring by CAISO Operators and Exceptional Dispatch in RTM.

Refer to the *BPM for Managing Full Network Model* for further details on the development and application of Nomograms together with examples.

Exhibit 3-8: Nomogram
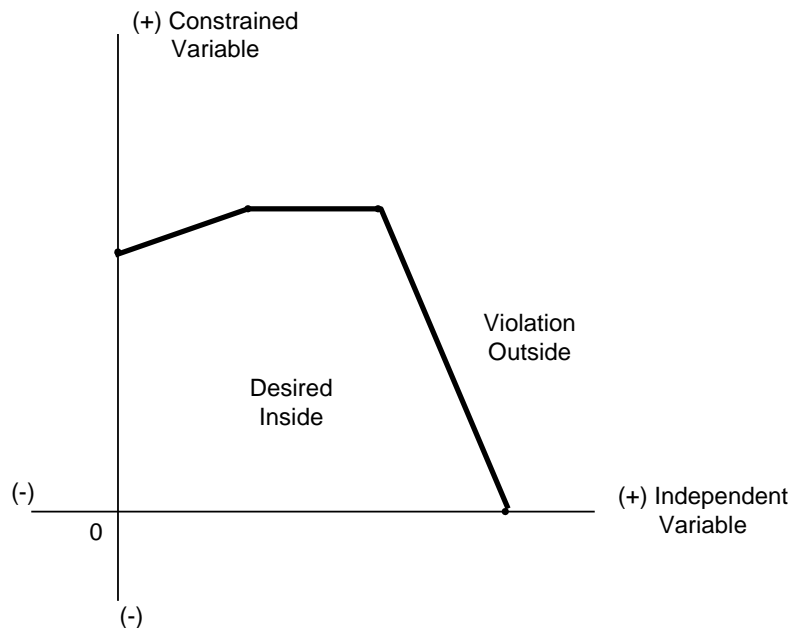
3.1.8   Transmission Element & Transmission Interfaces

The FNM incorporates limits on individual transmission lines and transformers, as well as for composite transmission paths called Transmission Interfaces, which are defined as a constraint on flows across one or more transmission facilities.

Limits on specific transmission facilities may be flagged as follows in the market optimization process:

➢ Enforced
➢ Monitored
➢ Ignored

As a general rule, all transmission limits are enforced in the market optimization process such that flows on the transmission system from the optimal resource Dispatch do not violate the specific limits. However, limits on specific transmission facilities may be flagged as only "monitored" or "ignored" in cases where the limits are suspected of being invalid, or are not enforced for reasons such as being in a MSS or IBAA. The enforcement flags are specified for all transmission facilities, Transmission Interfaces, and Nomograms, and are specified for each market type.

CAISO maintains a database of all such transmission limits, and their enforcement flag is maintained by CAISO's Regional Transmission Engineers.

Furthermore, individual transmission facilities and Transmission Interface definitions contain an attribute that defines the constraint as either:

➢ Competitive
➢ Non-Competitive

These attributes are used in the Market Power Mitigation process. See Section 6.5.3, Competitive Path Criteria.

A Transmission Interface represents the composite interface of two or more network branches (e.g., lines and transformers). These groups are defined by CAISO based on power system studies and the flow of power scheduled into the markets. A Transmission Interface is commonly identified by a name, such as Palo-Verde. A Transmission Interface or group of interfaces may be nested within a larger Transmission Interface.

Transmission Interfaces are treated as constraints in the Unit Commitment and dispatching processes. In other words, the flow of power across a path is limited to avoid system reliability concerns in the power system.

Limits that are defined by CAISO operating procedures are enforced in the market software to the extent that they are piecewise-linear and convex, or that they can be replicated through Contingency analysis. Limits on path flow and scheduling rights are enforced on interties. Generally, branch flow limits are enforced on the CAISO Controlled Grid that is within the CAISO Balancing Authority Area.

Limits are also enforced on schedules which comprise the CAISO Controlled Grid outside the CAISO Balancing Authority Area that is a network facility, to ensure that schedules remain within the Converted Rights that have been turned over to CAISO's Operational Control.

Branch flow limits are monitored but not enforced in Metered Subsystems, embedded and adjacent Balancing Authority Areas, and CAISO Controlled Grid networks outside the CAISO Balancing Authority Area. Constraints are also monitored but not enforced within the CAISO Balancing Authority Area if operational experience of Real-Time conditions determines that modeled flows do not match actual flows. Constraints are ignored only if monitoring them does not provide useful information for CAISO operations.

To attain uniqueness of prices related to transmission constraints, all constraints used to model transmission elements are formulated with additional slack variables.

Transmission Interfaces and constraints are further described in the *BPM for Managing Full Network Model, Section 4.2*.

3.1.9   Scheduling Points

A Scheduling Point is a location in the Base Market Model at which Scheduling Coordinators may submit Intertie Bids in the CAISO Markets.
A Scheduling Point typically is physically located outside of the CAISO Controlled Grid (e.g., at the point of interconnection between an external Balancing Authority Area and the CAISO Controlled Grid). NPTO Scheduling Points are within the CAISO Control Grid, but still outside the CAISO Balancing Authority Area. Default IBAA Scheduling Points may be mapped for modeling and pricing purposes to other physical locations as further described in Section 27.5 of the CAISO Tariff and the BPM for the Full Network Model.

Scheduling Points are listed on the CAISO website:

http://www.caiso.com/1f94/1f94cd5447620.html

Within the CAISO Balancing Authority Area, resources must schedule at actual physical location, either at the specific resource location or using aggregations approved by CAISO.

Within New PTO networks of Converted Rights that extend outside the CAISO Balancing Authority Area, imports and exports are scheduled at Scheduling Points that are not the actual location of Generation or Load in the other Balancing Authority Areas for which CAISO typically does not know the actual location when the market runs.

3.1.10   Unscheduled Flow Estimation

Unscheduled loop flows occur because, outside of California, the Balancing Authority Areas within the Western Interconnection rely on contract path scheduling between Balancing Authorities. This assumes that electricity flows along a designated point-to-point path when in fact electricity flows are distributed throughout the AC transmission network. For example, a contract path schedule of 100 MW over Intertie T1 may actually result in 80 MW of the schedule to flow over T1 and 20 MW of unscheduled loop flow over Intertie T2. If the CAISO does not account for the 20 MW of unscheduled loop flow on T2, it may accept CAISO Market Schedules on T2 assuming this 20 MW of capacity is available, thereby creating infeasible schedules and potentially scheduling more Energy to flow over the Intertie than the physical limit. Unscheduled loop flows can result from almost any transaction in the interconnected grid.

If the CAISO were to wait until Real-Time to recognize and manage the physical limits of Interties, there would be less flexibility to commit units to offset infeasible schedules. This may lead to re-dispatch of expensive Generation or even Exceptional Dispatches to resolve the infeasibility, leading to higher costs and Real-Time Congestion Offset uplift costs. Instead, the loop flow is incorporated into DAM as well as RTM, to produce feasible schedules with prices that more accurately reflect the conditions that will be experienced in Real-Time.

In order to model unscheduled loop flows, accurately enforce physical capacity limitations of the Interties, and incorporate reliability and outage information in the forward-looking horizons of DAM and RTM, the Full Network Model includes the transmission topology used by the EMS State Estimator for most or all external Balancing Authority Areas, and representations of sources and sinks in these areas. (In cases where the EMS network model does not include dynamically transferred resources of the CAISO Markets, market-only additions supplement the EMS model as needed.) The CAISO obtains the Demand Forecast and Outage data needed for this modeling from Reliability Coordinator (Peak Reliability) databases developed to coordinate reliability planning. For forecasted Interchange between Balancing Authority Areas, the CAISO uses the services of a vendor, with expertise in tracking scheduled Interchange transactions, to analyze current and recent historical ~~E-Tag~~E-Tag data for the WECC region. The CAISO combines the vendor's data on historical scheduled Interchange and projected future scheduled Interchange, as a weighted average of these time series. The CAISO also has the ability to scale the resulting forecasted Interchange to ensure that this input to the market optimization matches actual Real-Time conditions as closely as possible. Combining the Demand Forecast with the forecasted Interchange for a Balancing Authority Area produces the generation forecast for that area. In RTM, the CAISO can supplement this modeling with State Estimator results to match actual telemetered Real-Time flows by calculating compensating injections at Interties or other locations in the network.

3.1.11   Nodal Group Limit Constraints

In order to ensure AC convergence under Virtual Bidding, the software is capable of enforcing nodal group MW limit constraints on a location basis to limit the volume of Bids at a particular location or set of locations. These nodal group MW limits will only be used when an AC solution is not attainable within the IFM before the Day-Ahead Market clears. When a nodal group MW limit enforcement is needed, it will be applied to the total flow affected by both physical and Virtual Bids.

The CAISO will enforce nodal group MW limit constraints to help ensure AC power flow solutions. The process for determining whether to enforce nodal group MW limit constraints is shared between the Security Constrained Unit Commitment (SCUC) module and the transmission network analysis (TNA) module processing. The TNA will identify nodal groups where MW limits should be enforced and the SCUC will include the appropriate constraints in the optimization problem formulation.

To identify the enforced nodal group MW limit constraints, it is assumed that more injection (combined physical and virtual) is being awarded at specific points in the system than the system is really capable of supporting. Therefore the objective is to identify where excess injections have been awarded at key locations in the system. To accomplish this analysis, the first task is to look for PNodes where large injection awards have been made by ordering the PNodes according to the largest injection MW quantity relative to the MW limit at that PNode (i.e. absolute total injection MW divided by PNode MW limit expressed as a percentage at each location). The second task is to identify if the large MW injections are at key locations in the system. These key locations are pre-defined in a static list and determined based on an analysis of power flow studies. The list of key locations will be updated as network conditions change.

After the enforced constraints have been identified, they will be ordered in terms of those that have the largest relative percentage violation of their MW limit and the Pnodes that exceed a pre-defined threshold. The first iteration chooses the top N PNodes (configurable) from the ordered list. The configurable number will be initially determined by analysis of market simulation results and internal structured testing prior to the implementation of convergence bidding, and may be updated based on actual operating experience. If this iteration fails to lead to AC convergence then subsequent iterations will choose larger numbers of PNodes from the ordered list.

Once the nodal group MW limit constraints are identified and being enforced, the market software will calculate the corresponding PNode MW limits according to the following rules:

1) For PNodes that have physical Supply Resources, the nodal maximum MW limit will be defined to be the MW maximum of the physical Supply Resources based on the Master File PMax. The minimum nodal MW limit is set to zero as the default value.

2) For PNodes that have Demand Resources, the nodal minimum MW limit will be defined to be the negative of the Load Distribution Factor for the PNode times the CAISO Forecast of CAISO Demand MW value. The nodal maximum MW limit is set to zero as the default value.

3) Except for Default Laps and Trading Hubs, for PNodes that have no Generator or Demand connected then Virtual Bidding is not allowed. Virtual Bids are only

allowed where there are physical resources at the location associated with a PNodes.

4) The final Nodal Maximum MW Limits are the values calculated by the above rules multiplied by a configurable percentage, which is defined on a nodal basis.

5) The final Nodal Award Minimum MW Limits are the values calculated by the above rules multiplied by a configurable percentage, which is defined on a nodal basis.

6) The configurable percentages applied to the maximum and minimum MW limits will be based on an engineering analysis of power flows run with the Full Network Model. The percentages will be set to allow for the production of consistent AC solutions.

7) There are no Nodal Maximum MW limits imposed on Default LAPs or Trading Hubs directly.

If the automated iterative process described above does not result in achieving an AC solution, the ISO will identify PNodes that have physical Supply Resources that are on outage or not fully participating in the ISO market and manually set the nodal constraint as low as the zero.

For nodal group MW limit purposes, physical Supply and Virtual Supply Bids are treated as positive values. Physical Demand and Virtual Demand are treated as negative values. The Nodal Maximum MW Limit is a positive value indicating the limit of how much net physical Generation or Virtual Supply can be allowed at a PNode. The Nodal Award Minimum MW Limit is a negative value and indicates the limit of how much net physical Demand or Virtual Demand can be allowed at a PNode. Information for nodal group MW limits will be published to Market Participants in the similar way as other transmission constraints. Refer to the *BPM for Market Instruments*, Section 12.

Example

Three CNodes (A, B, and C) are connected to physical resources and have associated virtual injections.
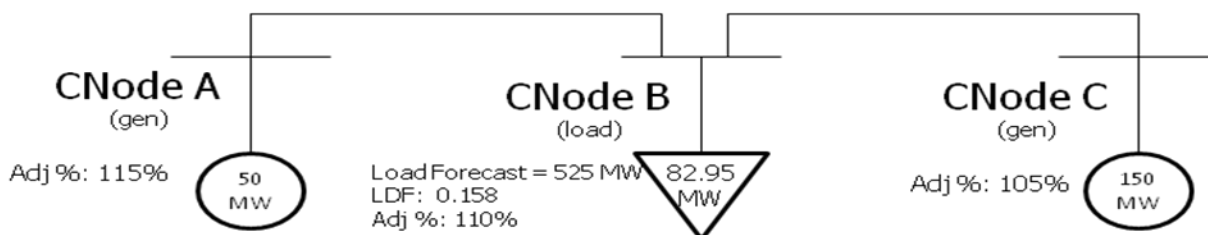
CNode A is connected to a Generator with a maximum MW value of 50 MW. CNode B is a load node. The CAISO Forecast of CAISO Demand is 525 MW and the load distribution factor is 0.158. CNode C is connected to a different Generator with a rating of 150 MW. Configurable

percentages were set to 115% and 105% for Generators at nodes A and C respectively, and 110% for the load node[16].

Model limit calculations:

    CNode A: 50 MW * 115%   = 57.5 MW
    CNode B: -525 MW * 0.158 * 110% = -124.425 MW (minimum limit)
    CNode C: 150 MW * 105%   = 157.5 MW

    (Minimum limits are set to zero for nodes A and C. Maximum limit is zero for node B)

3.1.12   Controllable Devices Modeling

The CAISO controlled grid includes controllable transmission devices that enable the CAISO as the balancing authority area and transmission operator to monitor and adjust the power flow on the CAISO controlled grid (An example of these devices include but not limited to ISO controlled HVDC, Phase Shifting Transformer, and any other controllable devices). Controllable transmission devices are designed to ensure the reliable and secure operation of the grid is maintained. Controllable transmission devices help control the power flow through transmission lines. The CAISO market systems optimizes the controllable transmission devices as part of its security constrained economic dispatch and security constrained unit commitment. The CAISO market systems will calculate and issue the optimal position for the controllable device to the transmission owner. Pursuant to operating procedures, the transmission owner modifies the controllable device pursuant to the CAISO market instruction.
The CAISO will not enforce the optimization of the controllable device in any of the CAISO Markets if the CAISO has determined that: (1) there are modeling inaccuracies, including inaccuracies in available data; or (2) doing so could result in adverse reliability impacts.

3.2   Locational Marginal Prices

The CAISO Markets are based on using an FNM coupled with LMPs. As noted above, the FNM is comprised of a detailed model of the physical power system network along with an accurate model of commercial scheduling and operational arrangements, to ensure that the resulting LMPs reflect both the physical system and the schedules produced by the market applications. Section 2.3 of the *BPM for Managing Full Network Model* describes the integration of the FNM and Market Operations.

The LMP is the marginal cost (expressed in $/MWh) of serving the next increment of Demand at that PNode consistent with transmission facility constraints, transmission losses, and the performance characteristics of the resources as detailed in Section 3.1. LMPs are calculated at PNodes, which are CNodes that are Modeling Points or have other informational value. LMPs

---

[16] The values 115%, 105% and 110% were selected for illustration purposes only. The values are not necessarily representative of values that are used in production.

for Aggregated Pricing Nodes (APNodes, which are groupings of PNodes used for bidding and pricing Generation and Demand in the CAISO Markets) are calculated after Market Clearing as the weighted average of the LMPs at their individual PNodes, using GDFs and LDFs as the weighting factors. Using the FNM in the DAM and the RTM incorporates Transmission Losses into the Market Clearing, and allows modeling and enforcing all network constraints. This results in LMPs for Energy that reflect the System Marginal Energy Cost (SMEC), Marginal Cost of Losses (MCL), and Marginal Cost of Congestion (MCC). The SMEC component of the LMP is the same for all PNodes, based on the selection of a certain Reference Bus. The MCL and the MCC vary across the network due to network characteristics and power flow patterns. The MCL is the SMEC times the Marginal Loss Factor at a PNode, where the Marginal Loss Factor is the derivative (i.e., rate of change) of the actual MW losses from that location to the Reference Bus, for a marginal (small) change in Load at the specified location. The Marginal Loss Factor is determined as part of the AC power flow solution during each Trading Hour in the DAM and each 15 minute interval in RTM. The MCC is the cost of congestion between a PNode and the Reference Bus. Because of the impact of the Reference Bus on the components of LMP, the CAISO uses a distributed Reference Bus for LMP calculation that weights the calculated components among PNodes throughout the CAISO Balancing Authority Area. Further details are in Section 3.1 and in subsections below.

3.2.1   LMP Disaggregation

In understanding the mechanics of LMP disaggregation, it is important to distinguish three separate reference variables that affect AC OPF results:

1) Angle reference: In Power flow calculations, the distribution of flows throughout the network involves calculation of phase angles, which are measured from a single reference location. There must be a single angle reference bus for the entire system (unless the system has multiple islands, in which case each island would have an angle reference bus). Although the angle reference bus is essential to Power flow calculations, CAISO's intent in specifying the Market design is that the selection of the angle reference bus does not affect the prices that result from the Market. Keeping the market results independent of the choice of angle reference bus involves the definition of the other reference variables for system Power balance and LMP disaggregation.

2) Power system slack: In an AC Power flow model, among the solution options is the use of a single bus or a distributed generation or distributed Load slack variable for system Power balance. Using a single slack bus means that adjustments to the MW output of system supply as a whole, to maintain a balance between supply and Demand, occur using Generation located at a single

bus. When the results of an AC OPF Market simulation are computed and a single slack bus is used in the Power flow calculations, it is common to use the LMP at this bus as the system Energy cost, since this is where incremental adjustments to supply occur to maintain the system Power balance. Since changes in Load at the slack bus are met by changes in Generation at the same bus, marginal losses are zero at the slack bus, and marginal losses at other buses are measured relative to the slack bus; this calculation of the LMP components is valid if and only if the change in supply occurs at the same location as the change in Load.[17] In contrast, a distributed Generation slack variable makes adjustments to all Generation to maintain the balance between supply and Demand, instead of adjusting a single Generator. With a distributed Load slack adjustments are made to Loads throughout the system in order to maintain Power balance. When a distributed slack variable is used (either a distributed Generation slack or a distributed Load slack), adjustments to maintain the system Power balance are independent of the choice of angle reference bus because they occur throughout the network. CAISO uses a distributed Load slack in all applications except IFM where distributed generation slack may be used.

3) LMP reference: The third reference variable involves the definition of the Energy and loss components on LMPs. The Energy component is the same at all locations in the network and is defined by the distribution of either Generation or Load, and the loss component is similarly defined as a measurement of the system's response to changes in injections or withdrawals that are distributed throughout the network. The concept of computing LMP components at a single reference bus, versus using a distributed reference that reflects adjustments that are spread throughout the network, is similar to the slack reference that is used for system Power balance. The calculations of system Power balance and LMP disaggregation can occur separately, but there is little reason (other than software configuration) to measure LMP components using a different reference than the Power balance equations. As is the case when a distributed slack variable is used for maintaining system power balance, the results of LMP disaggregation are independent of the choice of angle reference bus because the reference variable is distributed throughout the system. This meets CAISO's

---

[17] When changes in load at the slack bus are matched by changes in Generation at the same bus, flows between other buses in the network do not change, losses in the system do not change, and marginal losses are zero. However, if the change in load at one bus are matched by changes in Generation at other buses, then flows in the network do change, which causes losses in the system as a whole to change, and marginal losses (i.e., the change in system losses per increment of change in load) are not zero.

intent, in the Market design, that the selection of the angle reference bus does not affect the prices that result from the Market.[18]

If a single slack option is chosen, CAISO will choose a slack bus that is centrally located in the CAISO Balancing Authority Area. In case the distributed load slack option is chosen, the load slack adjustments are made to load throughout the system using system LDFs. When distributed generation slack is chosen, adjustments will be made to the generation output of generating units to maintain power balance. The selection of generating units, participating in the slack adjustments is made economically based on the amount of MW available for adjustments on the generating units.

The distinctions among these quantities can be seen by considering a two-bus example, in which 500 MW Generators are located at each Bus 1 and Bus 2 with a $30/MWh Bid at Bus 1 and a $100/MWh Bid at Bus 2. There is a Load of 250 MW at Bus 2. The transmission line from Bus 1 to Bus 2 has impedances as shown (reactance = X = 0.1, resistance = R = 0.0224, per unit) and a rating of 210 MW at each end. Each Generator has a large reactive Generation capability, and controls its own bus voltage to 1.0 per-unit.
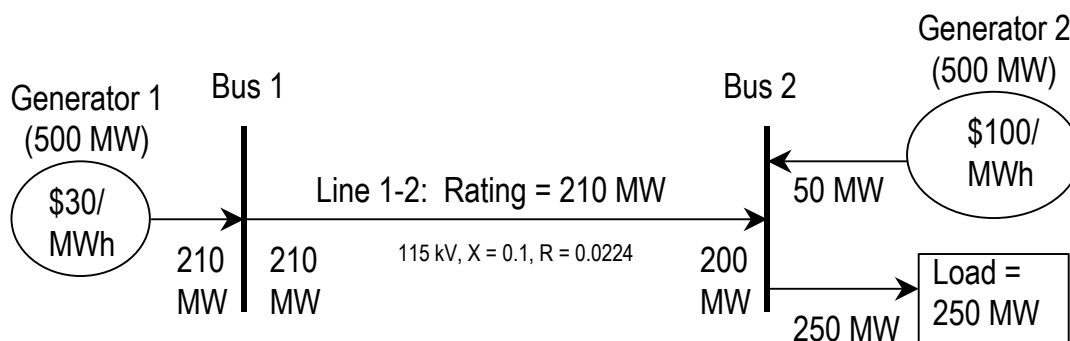
Generator 1 has the lowest Bid, but cannot serve all 250 MW of Load at Bus 2 due to the 210 MW limit on Line 1-2. Losses on Line 1-2 result in 200 MW reaching Bus 2, so the remaining 50 MW of Load at Bus 2 must be served by Generator 2. Additional Load at Bus 1 could be served by Generator 1 at $30/MWh, and additional Load at Bus 2 could be served at $100/MWh by Generator 2, so the total LMPs are $30 and $100/MWh at Bus 1 and Bus 2, respectively. For four alternative model formulations, the disaggregated LMP results are as follows:

---

[18] The independence of the LMP disaggregation using a distributed reference variable from the selection of angle reference bus is both a theoretical result, since the distribution of load or Generation is not affected by the choice of angle reference bus, and an empirical result that appears in the outputs of LMP software.

LMP Location	Total LMP	Energy	Loss	Congestion	Shadow Price
LMP Reference:	Single Bus #1	Angle Ref.:	Bus 1		$60.59/MW
Bus 1	$30/MWh	$30/MWh	$0/MWh	$0/MWh	
Bus 2	100	30	3.12	66.88	
LMP Reference:	Single Bus #2	Angle Ref.:	Bus 2		60.59
Bus 1	30	100	-9.41	-60.59	
Bus 2	100	100	0	0	
LMP Reference:	Distributed	Angle Ref.:	Bus 1		60.59
Bus 1	30	100	-9.41	-60.59	
Bus 2	100	100	0	0	
LMP Reference:	Distributed	Angle Ref.:	Bus 2		60.59
Bus 1	30	100	-9.41	-60.59	
Bus 2	100	100	0	0	

In the first model formulation, LMP components are computed using a single bus (Bus 1) as the reference for LMP disaggregation and the angle reference bus is Bus 1. Bus1's LMP defines the System Marginal Energy Cost of $30/MWh. As noted above, additional load could be served at Bus 1 for $30/MWh, with no additional losses or congestion. Since this first model uses a single reference bus at Bus 1, the difference between loss and congestion prices at the two buses is stated as non-zero prices at Bus 2. Relative to the reference bus at Bus 1, running AC power flow software to account for interactions between MW and MVAr flows produces a "loss penalty factor" at Bus 2 of 0.9059: if the flow at Bus 1 were increased by an increment of 1 MW, the incremental change in flow at Bus 2 would be 0.9059 MW, after losses in the line. (Numbers in this discussion are rounded for presentation purposes.) That is, serving an additional 1 MW of Load at Bus 2 could be served by the less expensive Generator at Bus 1, if the constraint limit at Bus 1 and the output of Generator 1 were increased by (1/0.9059) = 1.1039 MW. This represents both the Energy that arrives at Bus 2 and the Energy that is lost in the transmission network, and the Marginal Loss Factor = 1.1039 – 1 = 0.1039. The Marginal Cost of Losses at Bus 2 = Marginal Loss Factor * System Marginal Energy Cost = 0.1039 * $30/MWh = $3.12/MWh. The Marginal Cost of Congestion at Bus 2 = total LMP - System Marginal Energy Cost - Marginal Cost of Losses = 100 – 30 – 3.12 = $66.88/MWh. Because the incremental savings to the system due to the 1 MW relief of the network constraint, which is called the "shadow price" of the constraint, needs to account for the MW originating at Bus 1 vs. the MW arriving at Bus 2, the shadow price = 0.9059 * $66.88/MWh = $60.59 per MW (using a 1-hour Dispatch interval).

In the second model formulation, Bus 2 is the single reference bus for LMP disaggregation, and Bus 2 is the angle reference bus. Bus1's LMP defines the System Marginal Energy Cost of $100/MWh. Placing the Reference Bus for LMP decomposition at Bus 2, the Marginal Loss Factor is 1 – 0.9059 = 0.0941, and the Marginal Cost of Losses = 100 * 0.0941 = $9.41/MWh. The constraint limit applies at each end of the line from Bus 1 to Bus 2, and is a binding constraint at Bus 1, where the flow is higher. When the model uses a single reference bus at Bus 2, the difference between congestion prices at the two buses is stated as a non-zero price at Bus 1, and the difference in congestion prices equals the shadow price of the constraint since the constraint is limiting flows at the same location. Although the total LMPs are the same in all cases, this difference between the LMP loss components at the two buses is three times as high as in the first model formulation and has depended simply on the choice of the Reference Bus, which would thus affect Settlements that are based on LMP components. This leads CAISO uses a distributed Reference Bus that depends on the distribution of resources throughout the CAISO Balancing Authority Area, instead of on the choice of a single reference point. The shadow price of the constrained line limit is $60.59 regardless of the choice of reference bus or LMP reference formulation.

The third and fourth model formulations use the inputs as the first and second ones, but the distributed reference formulation is used for LMP disaggregation instead of the single bus formulation, where the distribution is based on Load. By using the distributed reference, the LMP disaggregation does not depend on the selection of the angle reference bus. Since the Load is only at Bus 2 in this example, the LMP disaggregation is the same as if Bus 2 were used as a single reference bus; note that the value of the LMP loss component is $0/MWh in this case. That is, using the distributed reference makes the LMP results independent of the selection of the angle reference bus. As noted above, CAISO intends to use a distributed reference for LMP disaggregation as well as using a distributed slack bus for Power balance.

The same independence of the LMP disaggregation for alternative selections of the angle reference bus can be seen for a three-bus example:

Generator 1
(500 MW)

Bus 1

$40/
MWh

348.5
MW

Load =
200 MW

All lines: X = 0.1, R = 0.02

Line 1-2: Rating = 100 MVA

49.5
MW

99
MW

Line 1-3:
Rating=100 MVA

97
MW

Bus 2

0 MW

49.0
MW

49.0
MW

48.5
MW

Generator 2
(500 MW)

$55/
MWh

250 MW

Line 2-3:
Rating = 100 MVA

54.5
MW

$60/
MWh

Generator 3
(500 MW)

Bus 3
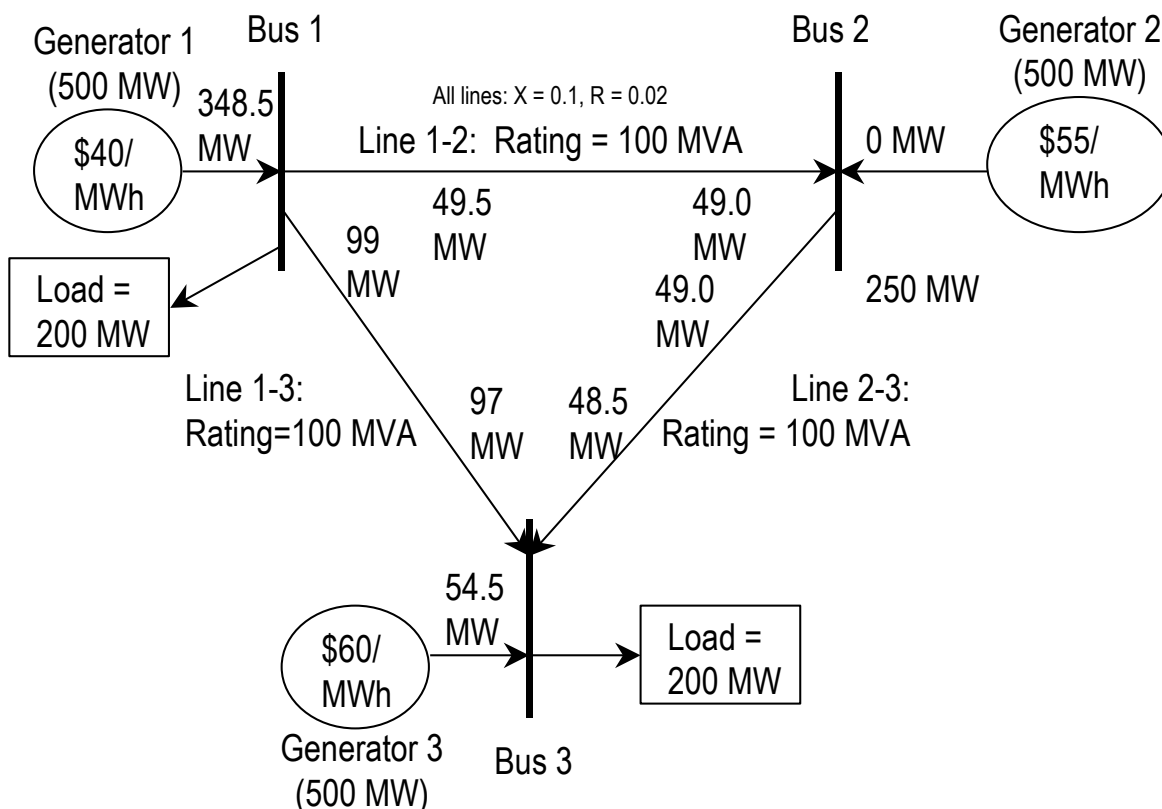
Load =
200 MW

Generators 1, 2, and 3 (located at Buses 1, 2, and 3, respectively) each have 500 MW capacity, and have Bids of $40, $55, and $60/MWh, respectively. Buses 1 and 3 each have 200 MW of Load. Lines 1-2, 1-3, and 2-3 have equal impedances, and ratings of 100 MVA each. Generator 1 can serve the entire Load at Bus 1, but can only produce 148.5 MW to serve the Load at Bus 3 because of the limit on Line 1-3's capacity. (Because MVAr reactive Power flows in addition to MW Power flows, the 100 MVA capacity amounts to only 99 MW of real Power.)

For the alternative model formulations of single-bus or distributed LMP disaggregation, and selections of angle reference bus, the disaggregated LMP results are as follows:

LMP Location	Total LMP	Energy	Loss	Congestion	Shadow Price
LMP Reference:	Single Bus #1	Angle Ref.:	Bus 1		$26.30/MVA
Bus 1	$40/MWh	$40/MWh	$0/MWh	$0/MWh	
Bus 2	49.9	40	0.83	9.07	
Bus 3	60	40	1.67	18.33	
LMP Reference:	Single Bus #2	Angle Ref.:	Bus 2		26.30
Bus 1	40	49.9	-1.02	-8.89	

LMP Location	Total LMP	Energy	Loss	Congestion	Shadow Price
Bus 2	**49.9**	49.9	0	0	
Bus 3	60	49.9	1.03	9.07	
LMP Reference:	**Single Bus #3**	**Angle Ref.:**	**Bus 3**		26.30
Bus 1	**40**	60	-2.41	-17.59	
Bus 2	**49.9**	60	-1.21	-8.83	
Bus 3	60	60	0	0	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 1**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	60	50	1.04	8.96	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 2**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	**60**	**50**	**1.04**	**8.96**	
LMP Reference:	**Distributed**	**Angle Ref.:**	**Bus 3**		26.30
Bus 1	40	50	-1.00	-9.00	
Bus 2	49.9	50	0.02	-0.11	
Bus 3	**60**	**50**	**1.04**	**8.96**	

Similarly to the two-bus example, LMP components in the first through third model formulations are computed using a single bus as the reference for LMP disaggregation, and the angle reference bus is varied between the three models. The difference among the LMP loss components at the three buses ranges from $1.67/MWh when Bus 1 is the reference bus to $2.41/MWh when Bus 3 is the reference bus, and the congestion component varies by offsetting amounts. (The total LMP is not affected by the selection of the reference bus, the Energy component is the same at each bus, and Total LMP = Energy + Loss + Congestion.) In the fourth through sixth model formulations, the distributed Load reference is used for LMP disaggregation, and the LMP components do not vary with the selection of the angle reference bus. Recall that the LMP loss component had the same value as if a single LMP reference bus were used at Bus 2 in the two-bus example, in which Load only exists at Bus 2, and therefore the Load-weighted average LMP loss component in that example is $0/MWh. In the three-bus example, there are equal amounts of Load at Buses 1 and 3, so the Load-weighted average LMP loss component is $0.02/MWh, which is closer to $0/MWh than to either of the LMP loss component values at these buses.

The following subsections describe each of the three cost components of LMP.

The *BPM for Managing Full Network Model, Section 4* describes the network factors that are required as part of the LMP calculation.

3.2.2 System Marginal Energy Cost

System Marginal Energy Cost (SMEC) is the component of the LMP that reflects the marginal cost of providing Energy from a CAISO-designated reference location.

CAISO uses a distributed Load reference for LMP decomposition, instead of a single slack reference bus. A distributed Load reference approach calculates the LMP components based on where the Demand actually is, using Load Distribution Factors that are updated on an ongoing basis. The use of a distributed slack for power flow calculation is discussed in the *BPM for Managing Full Network Model, Section 3.3*.

Individual LMPs for a given time period each have the same SMEC component of LMP. It is important to emphasize that the LMP value itself is not affected by how SMEC is derived.

3.2.3 Marginal Cost of Losses

Marginal Cost of Losses (MCL) is the component of LMP at a PNode that accounts for the real power Marginal Losses, as measured between that CNode and the distributed Load reference. The MCL is calculated as the product of SMEC and the Marginal Loss Factor at that PNode. The MCL at a particular PNode may be positive or negative, depending on the submitted Bids. The Marginal Loss Factors are derived by the market optimization software (IFM/RTM).

All scheduled Energy Transactions (including Demand, Supply, and Inter-SC Trades) are settled using the loss component of the LMP at the location of the transaction. For example, when a Supply is paid for the Energy that it delivers, and the loss component of its LMP is negative, it is charged (negative payment) for losses. Further information on payment for losses is included in the *BPM for Settlements and Billing*.

3.2.4 Marginal Cost of Congestion

Marginal Cost of Congestion (MCC) is the component of LMP at a PNode that accounts for the cost of Congestion, as measured between that CNode and a Reference Bus. Section 2.3.2.3 of this BPM and Attachment A of the *BPM for Managing Full Network Model* describe the use of the Reference Bus. The MCC is calculated based on a linear combination of the Shadow Prices of all binding constraints in the network, each multiplied by the corresponding Power Transfer Distribution Factor within the minimum effectiveness threshold. Shadow Prices in IFM include

impacts from Virtual Awards (Supply and Demand) on binding constraints, including nodal group MW limit constraints. The MCC at a particular PNode may be positive or negative. PTDFs are calculated using sensitivity analysis on the AC power flow solution for each Trading Hour in the DAM and each 15 minute interval in the RTM. To ensure uniqueness of prices when there are binding constraints in the network, the market clearing process would create a shadow price for the Transmission Constraint, only when the relaxation of the constraint would result in a reduction in the total cost to operate the system.

3.3   Market Interfaces

Exhibit 3-11 presents an overview block diagram with a description of the principle supporting computer system activities as presented in Attachment B, Market Interfaces.

Exhibit 3-9: Market Interfaces
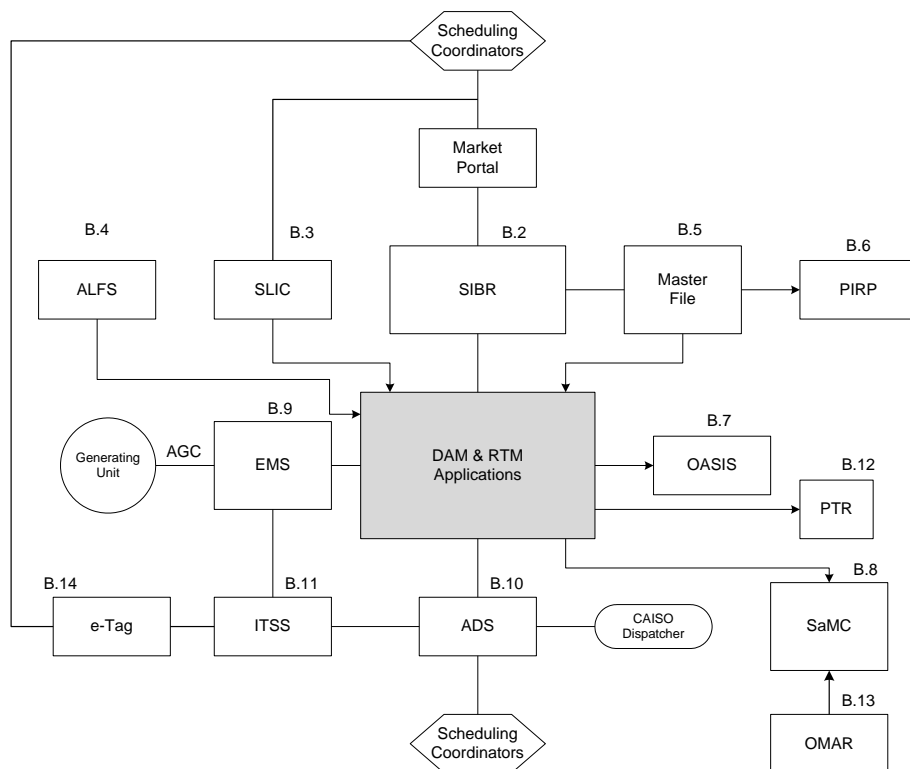
ALFS   = Automated Demand Forecasting System
SIBR   = Scheduling Infrastructure & Business Rules
SLIC   = Scheduling & Logging of Outages
PIRP   = Participating Intermittent Resource Program
OASIS = Open Access Same Time Information System
SaMC   = Settlements & Market Clearing System
EMS   = Energy Management System
ADS   = Automated Dispatch System
ITSS   = Interchange Transaction Scheduling System
PTR   = Post Transaction Repository
OMAR   = Operational Meter Analysis & Reporting
e-Tag   = Electronic Tagging System

4.   Ancillary Services

Welcome to the *Ancillary Services* (AS) section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- ➢ A description of each of the AS Regions
- ➢ How CAISO determines AS requirements
- ➢ How CAISO procures AS
- ➢ How CAISO calculates AS Marginal Prices
- ➢ Other AS considerations
- ➢ Certification and testing requirements

4.1   Ancillary Services Regions

AS Regions are network partitions that are used to explicitly impose regional constraints in the procurement of AS, where the AS Region is defined as a set of PNodes. Regional AS procurement from resources associated with the CNodes defining the region is constrained by a lower and upper requirement. The upper requirement may be defined for each AS and also for upward AS.

AS regional constraints reflect transmission limitations between AS Regions that restrict the use of AS procured in one AS Region to cover for i) Outages in another AS Region and ii) constraints between the regions. AS regional constraints secure a minimum AS procurement (to ensure reliability) and/or a maximum AS procurement target (that increases the probability of deliverability of AS to each Region), such that the total AS procurement among Regulation Up, Spinning Reserve, and Non-Spinning Reserve reflects the current system topology and deliverability needs. Ancillary Service Regions and Sub regions are defined in the CAISO Tariff in Section 8.3.3. The CAISO may only establish New Ancillary Service Regions and Sub regions after first conducting a stakeholder process, and then only through the filing of a tariff amendment with the FERC (See Section 4.1.2, [Ancillary Services Region Changes Process], below, for more information).

4.1.1   Ancillary Services Region Definition

There are always at least two AS Regions with non-zero minimum procurement limits applied:

- ➢ **Expanded System Region** – The Expanded System Region is defined as the entire CAISO Balancing Authority Area plus all System Resources at Scheduling Points at an outside boundary of the CAISO Balancing Authority Area. Total CAISO AS procurement requirements for each of the four types of AS that are further described in the *BPM for Market Instruments* (Regulation Up, Regulation Down, Spinning Reserve and Non-

Spinning Reserve) are procured from certified Generating Units and Participating Loads, PDRs (non-spinning reserve only) and System Resources within the Expanded System Region. Procurement requirements for Regulation Up and Regulation Down Mileage are enforced at the Expanded System Region only. There are no Regulation Mileage procurement requirements at the sub-regional level.

➢ **System Region** – The System Region is defined as the sub-set of certified resources defined in the Expanded System Region that are located internal to the CAISO Balancing Authority Area. The minimum AS regional constraints for the AS System Region are only a percentage of the AS requirements for the Expanded System Region, currently at 50%, to limit the AS procurement from System Resources for reliability purposes. The purpose of this limitation is to guard against the consequences of losing interconnection tie facilities, which would limit the AS procurement, i.e., AS delivered over a tie cannot protect the tie itself.

Besides the Expanded System Region and the System Region, eight other AS Regions are defined to ensure appropriate distribution of the AS procured for the CAISO Balancing Authority Area. These AS Sub-Regions are defined to account for expected Congestion on the Transmission Interfaces (internal to the CAISO Balancing Authority Area), as well as other system conditions, that may impact the ability of the CAISO to convert AS reserves to Energy without exacerbating Congestion on the paths that are internal to the CAISO Balancing Authority Area.

The primary purpose of the eight sub-AS Regions is to account for expected Congestion on Path 15 and Path 26. For each given hour of AS procurement, one of the following conditions is assumed:

1) No congestion forecasted on either of these two Transmission Interfaces.

2) Forecasted congestion on Path 26 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 26.

3) Forecasted congestion on Path 15 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 15.

4) Forecasted congestion on Path 15 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 15.

5) Forecasted congestion on Path 26 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 26.

6) Forecasted congestion on Path 15 in the north to south direction simultaneous with south to north Congestion on Path 26. While this scenario is expected to be rare, it can be addressed by setting maximum procurement limits on each of the south of Path 26 AS sub-Region and the north of Path 15 AS sub-Region.

7) Forecasted congestion on Path 15 in the south to north direction simultaneous with north to south Congestion on Path 26. While this scenario is expected to be rare, it can be addressed by setting minimum procurement limits on each of the south of Path 26 AS Sub-Region and the north of Path 15 AS sub-Region.

For each of these conditions where congestion is assumed (Items 2 through 7 above), the AS Sub-Region may include the System Resources that are interconnected to that portion of the CAISO Controlled Grid. The determination of whether or not to include the System Resources in the AS Sub-Region depends on the nature of the system conditions, including the expected loading on the Transmission Interfaces that interconnect System Resources to the CAISO Controlled Grid

Based on these criteria, there are eight AS Sub-Regions in addition to the Expanded System Region and the System Region, as follows:

Exhibit 4-1: Summary of Initial AS Regions

	AS Region Name	**Description of AS Region (set of resources included in AS Region)**		**AS Region Status**
		Internal CAISO Balancing Authority Area	**Intertie Resources (current Scheduling Points)**	
1	*Expanded System*	All internal Generators	All	Active
2	*System*	All internal Generators	None	Active
3	*South of Path 15*	All Generators residing South of Path 15	None	Active
4	*Expanded South of Path 15*	All Generators residing South of Path 15	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active
5	*South of Path 26*	All Generators residing South of Path 26	None	Active
6	*Expanded South of Path 26*	All Generators residing South of Path 26	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active

	AS Region Name	Description of AS Region (set of resources included in AS Region)		AS Region Status
		Internal CAISO Balancing Authority Area	Intertie Resources (current Scheduling Points)	
7	*North of Path 15*	All Generators residing North of Path 15	None	Active
8	*Expanded North of Path 15*	All Generators residing North of Path 15	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active
9	*North of Path 26*	All Generators residing North of Path 26	None	Active
10	*Expanded North of Path 26*	All Generators residing North of Path 26	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active

All AS Regions shown in Exhibit 4-1 are "active". However, this does not necessarily mean that a minimum (or maximum) procurement limit is enforced for each of these AS Sub-Regions for a given hour. The term "active" here indicates that the AS Sub-Region is defined in the CAISO Tariff, and is included in the daily determination of applicable Regional AS limits. However, an AS Sub-Region may be "active" but also have a zero MW minimum procurement limit and a 9,999 MW maximum procurement limit, which effectively renders the AS Sub-Region as unconstrained.

AS requirements, procurement, and pricing are expressed by AS Region. The minimum and/or maximum procurement constraints are each determined individually and serve as separate constraints on the procurement of resources. A purchase of AS capacity in a specific Location on the grid may contribute to meet the requirements of several AS Regions simultaneously.

As conditions evolve, the CAISO may need to establish additional AS Regions to manage AS procurement limits for sub-AS Regions. These conditions may include:

➢ A pocket of Generation or Load for which more localized limits are needed to ensure sufficient capacity procurement under certain system conditions

➢ A System Resource at a Scheduling Point from which CAISO foresees a need to limit the AS procurement, under certain system conditions

CAISO follows the AS Region change process described in the next section, as power system conditions warrant.

4.1.2　Ancillary Services Region Change Process

The CAISO will look at a number of technical factors in determining whether to consider adjusting the boundaries of the existing Ancillary Service Regions or creating a new Ancillary Service Region. These factors include, but are not limited to, operational reliability needs, the pattern of Load growth in the CAISO Balancing Authority Area, the addition of new generating resources, the retirement of existing generating resources, the addition of new transmission facilities, changes in regional transmission limitations, changes in Available Transfer Capacity, and extended transmission or generating resource outages.

In addition, as part of a CAISO consideration of a proposed AS region change, the CAISO will conduct a market impact analysis to determine whether the changes being considered create market power issues.

The CAISO will submit its analysis and proposed action to a stakeholder process, in which stakeholders will be able to comment on any new market mitigation measures proposed in the AS region change proposal.

Finally, after consideration of stakeholder comments, the CAISO will state any intended changes to the proposed AS region change, or issue a revised analysis and then submit its proposed AS region change to the FERC as part of a Tariff Amendment filing.

4.2　Ancillary Services Requirements

The requirements for Ancillary Services (AS) are determined by CAISO in accordance with the applicable WECC and NERC reliability standards.

AS Bids from resources internal to the CAISO Balancing Authority Area do not compete for the use of the transmission network in the market optimization applications. Rather, AS is procured on a regional basis, where the AS Region is defined as a set of PNodes, including Scheduling Points, on the FNM. The CAISO may set minimum and maximum procurement limits for each AS Region, for each service, and for each hour, to ensure Local Reliability Criteria are met.

Accordingly, the CAISO establishes minimum AS requirements for the "Expanded System Region," for each AS type, taking into consideration:

  ➢ Loads and generation Path Contingency deratings
  ➢ Path Total Transfer Capability (TTC)
  ➢ Largest single Contingency (on-line Generating Unit)

CAISO may establish minimum and/or maximum AS procurement limits for each AS Region, taking into consideration one or more of the following factors:

- ➤ Loads and generation Path Contingency deratings
- ➤ Path TTCs
- ➤ Largest single Contingency (on-line Generating Unit or in-service transmission)
- ➤ Forecasted path flows
- ➤ Other anticipated local operating conditions for Load and/or Generation pocket AS Regions

The minimum AS limit for the Expanded System Region reflects the quantities of each Ancillary Service required to meet the applicable WECC and NERC reliability standards for the CAISO Balancing Authority Area

The minimum procurement limit for AS in the System Region, which is defined as the Expanded System Region minus the System Resource at Scheduling Points, is set to a proportion of the minimum procurement limits of the Expanded System Region. The current default is 50%, which may be changed based on system conditions and CAISO Operator decision. CAISO posts the percentage of procurement limit from imports.

In addition to the System and Expanded System Regions, the procurement limit(s) for any given AS Region may be:

- ➤ **Zero (or infinity for maximum limit)** – Indicating that there are no expected limitations, associated with the transmission path(s) adjoining the AS Region to other AS Regions, on the deliverability of AS procured system-wide; or

- ➤ **Non-zero** – Such a limit is based on factors that have a direct effect on the system constraint for which the AS Region was intended to manage.

For a given AS Region in a given interval, if the maximum total upward AS limit is set to a value less than the sum of the minimum limits for individual upward AS types, then the maximum total upward AS limit will be relaxed, if necessary, to uphold the minimum procurement limits for individual AS types. Otherwise, the total upward AS limit can bind simultaneous with binding minimum limits for individual upward AS types.

The CAISO considers the following factors when establishing a minimum or maximum limit for each AS sub-Region:

➤ The CAISO Forecasts of CAISO Demand

➤ The location of Demand within the Balancing Authority Area

➤ Information regarding network and resource operating constraints that affect the deliverability of AS into or out of a AS sub-Region

➤ The locational mix of generating resources

➤ Generating resource outages

➤ Historical patterns of transmission and generating resource availability

➤ Regional transmission limitations and constraints

➤ Transmission outages

➤ Available Transfer Capacity

➤ Day-Ahead Schedules or RTM Intertie Schedules

➤ Whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag

➤ Other factors affecting system reliability

The determination of a sub-Regional minimum procurement related to a transmission outage is based on the N-1 TTC of the path minus the expected N-0 flow on the path, where the expected N-0 flow on the path is determined from previous market solutions for similar conditions. The N-1 TTC of the path is the effective TTC of the path when the single largest Contingency is taken on an element of that path.

For example, consider a path that is comprised of three transmission lines, and which has a normal TTC of 1000 MW. For a particular hour of the next day's market, the expected flow is 800 MW, which is below the N-0 TTC. However, if the system experiences a loss of one of the lines that comprise this path, the N-1 TTC of the path is de-rated to 500 MW. Therefore, the impact of supplying Energy to CAISO Demand for an N-1 Contingency on this path is 300 MW, since the 800 MW of N-0 flow must be reduced to 500 MW for that Outage.

If the CAISO changes its rules to determine minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the CAISO will issue a Market Notice to inform Market Participants.

4.2.1   Self-Provided Ancillary Services

This section is based on CAISO Tariff Section 8.6.2.

As stated in the Overview, Generating Units and Participating Loads and PDRs certified for AS may submit Submissions to Self-Provide an AS in the IFM. Self-Provided AS effectively reduces the aggregate AS requirements that must be met from AS Bids within the same AS Region, and reduces the AS Obligation for the SC Self-Providing the AS, in the AS cost allocation. For submissions to self-provide Regulation Up or Regulation Down, the price for the capacity reservation shall be $0/MWh and the price for Mileage shall be $0.

The CAISO performs a two-step process to qualify Submissions to Self-Provide AS (referred to as "SPAS"):

4.2.1.1   AS Self-Provision Qualification

Before the market optimization is performed, the CAISO qualifies all Submissions to Self-Provide AS with respect to (i) resource certification to provide the requested Self-Provided AS, (ii) feasibility with respect to the Resource capacity limits, (iii) feasibility with respect to the relevant Resource ramp rate limits, and (iv) total self provision from all Resources with respect to any maximum Regional procurement Limit. These AS Self-Provision qualifications are performed separately for each AS type.

For item (iv) above, If the total Submissions to Self-Provide an AS exceeds the maximum System Region and regional requirement for the relevant AS in an AS Region, then Self-Provided AS is pre-qualified pro-rata with respect to their Submissions to Self-Provide AS. When there are over-lapping AS Regions defined, CAISO enforces a priority order on the AS Regions for the pro-rata qualification processing. Finally, after all regional requirements are enforced for determination of pre-qualified Self-Provided of AS, the System requirements are enforced to ensure that the total qualified Self-Provided AS does not exceed the System Region AS requirements.

➢ This priority order only applies to the qualification of Self-Provided AS in an AS Region where a maximum AS procurement limit is specified. Unlike minimum AS Region procurement limits, which are specified for each AS type individually, a maximum procurement limit is enforced on all upward AS types in the AS Region collectively not to exceed the System Region AS requirements.

➢ Therefore, when the maximum procurement limit is reached within an AS Region due to over-supply of self-provision of upward AS, these self-provision schedules are disqualified on a pro-rata bases starting with the lowest priority AS types. The priority of

upward AS types (meaning the hierarchy of valuing upward AS types), from highest to lowest, is as follows:

  ➢ Regulation Up (highest priority)
  ➢ Spinning Reserve
  ➢ Non-Spinning Reserve (lowest priority)

4.2.1.2   Final Qualification Process

After the AS Self-Provision qualification process is complete, a second phase of Self-Provided Ancillary Services (SPAS) qualification takes place internal to the market optimization (in Day-Ahead or Real Time). The purpose of this second phase of qualification is to determine if any of the capacity for initially qualified SPAS (from the AS Self-Provision qualification process) is needed for Energy. If the market optimization determines that capacity submitted as SPAS is needed as Energy to resolve transmission constraints and/or satisfy the energy balance constraint (i.e., solve problem locally before looking at larger LAP Load reductions), then such Self-Provided AS capacity is partially or entirely disqualified and converted to Energy. In DAM, this conversion is possible when an Energy Bid has been submitted. In RTM, an Energy Bid is required for SPAS. Consistent with the requirements in Section 8.6.2 of the CAISO Tariff, Submissions to Self-Provide Ancillary Services are conditional to the CAISO finding that the capacity is not needed for Energy. In the event that a portion of Submission to Self-Provide Ancillary Services is not qualified, that portion of Self Provided AS will not count towards the SC's Ancillary Services Obligation (See Section 11.10.3.2 of the CAISO Tariff).

Key in this determination is identifying all Resources that are subject to the second phase of the qualification. For this purpose, a special designation flag is maintained in the CAISO Master File and sent to market applications to indicate whether a resource is subject to the optimized qualification of SPAS. This flag shall be set to "YES" for all resources with an offer obligation pursuant to a contractual or tariff obligation (Resource Adequacy Resource (RAR) or an RMR Unit). For release 1 of MRTU, this flag is not market specific, nor is it capacity specific. This flag, hereafter referred to as the SPAS Optimization Flag, shall apply to all the capacity of a given resource, for all markets.

Based on the SPAS Optimization Flag, and the results of the AS Self-Provision qualification process, all SPAS capacity is labeled as one of the following for consideration in the final qualification process:

  ➢ For SPAS Optimization Flag "NO" resources, SPAS capacity qualified in the AS Self-Provision qualification process is considered unconditionally qualified, or simply *qualified*.

> ➢ For SPAS Optimization Flag "YES" resources, SPAS capacity qualified in the As Self-Provision qualification process is considered *conditionally qualified*

> ➢ Regardless of the SPAS Optimization Flag, SPAS capacity that is unqualified in the AS Self-Provision qualification process is considered *conditionally unqualified*

4.2.1.2.1   Qualified SPAS

All SPAS capacity classified as *qualified* for the final SPAS qualification process undergoes no further qualification processing and this capacity is not converted to Energy in the market optimization

4.2.1.2.2   Conditionally Qualified SPAS

All SPAS capacity classified as *conditionally qualified* for the final SPAS qualification process may be converted to Energy to resolve transmission constraints and/or satisfy the Energy balance constraint. Such capacity is not converted to Energy unless all Economic Energy Bids are exhausted to meet these constraints, but is converted before other Self-Schedules are adjusted.

4.2.1.2.3   Conditionally Unqualified SPAS

All SPAS capacity classified as *conditionally unqualified* for the final SPAS qualification process may be converted to *qualified* SPAS. If SPAS was unqualified in the AS Self-Provision qualification process due to excess SPAS from all resources in a given AS Region, capacity classified as *conditionally qualified* on a resource that is converted to Energy in the final qualification process creates an opportunity for conditionally unqualified SPAS from other Resources in that same AS Region to qualify.

Exhibit 4-2: Qualification Process of Submissions to Self-Provide an AS
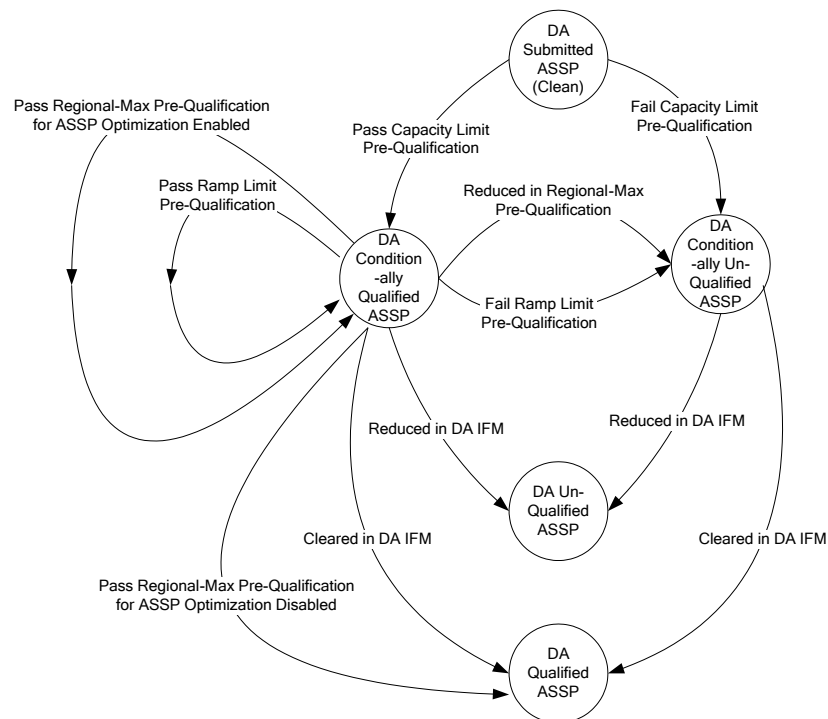
4.2.2   Conversion of Conditionally Qualified SPAS to Energy

This section is based on Section 8.6.2 of the CAISO Tariff. For the purpose of optimally converting *conditionally qualified* SPAS to Energy, a multi-segment Bid Curve is generated for each resource for consideration in the AS procurement optimization.

The most simplistic case is where a resource only provides Economic AS Bids, with no SPAS. In this case, the AS Bid is not modified for conversion of AS to Energy.

In the case where capacity from an SPAS Optimization flag "NO" Resource is *qualified* in the AS Self-Provision qualification process, then this capacity is not represented by any AS Bid segment, and therefore cannot be converted to Energy.

In the case where a SPAS Optimization flag "YES" Resource is *conditionally qualified* in the AS Self-Provision qualification process, then this capacity is assigned a penalty price P1 Bid segment, which is an artificially set at a negative price, P1, such that this capacity is cleared as AS in the market optimization before any other positive priced Economic Bids are cleared. This enables the optimization software to effectively apply a priority to the *conditionally qualified* SPAS over economically priced AS, but also allows the optimization to recognize this capacity

as less economical compared to the penalty price associated with binding transmission constraints or satisfying the Energy balance constraint. That is, if a transmission constraint becomes binding, the optimization attempts to dispatch Energy from all effective resources with Economic Energy Bids optimally to resolve the constraint. If all such Economic Bids are exhausted and the constraint still exists, then the optimization naturally finds the most optimal solution is to not clear the minimal portion of the *conditionally qualified* SPAS so that just enough Energy can be dispatched on that resource to relieve the constraint. This process effectively optimally determines exactly how much of the *conditionally qualified* SPAS can ultimately be *qualified.*

4.2.3   Conversion of Conditionally Unqualified SPAS to Qualified SPAS

This section is based on Section 8.6.2 of the CAISO Tariff. In the same process of optimally converting *conditionally qualified* SPAS to energy, a second penalty priced AS Bid Curve segment is inserted to represent the amount of unqualified SPAS determined in the AS Self-Provision qualification process, regardless of the SPAS Optimization flag indication. This penalty price Bid segment is administratively set to a smaller penalty price than for the *conditionally qualified* SPAS described above.

The purpose of classifying unqualified SPAS from the AS Self-Provision qualification process as *conditionally unqualified* is to allow this unqualified SPAS to be "re-qualified" if (i) it was originally unqualified because of a surplus of total SPAS for a given AS Region, and (ii) *conditionally qualified* SPAS on Resources in that AS Region was converted to Energy in the final qualification process.

Because the penalty price Bid segment for *conditionally unqualified* SPAS is priced higher than the *conditionally qualified* SPAS for all resources (a smaller negative penalty price), it is cleared as qualified SPAS after all conditionally qualified SPAS Bid segments are cleared, and before Economic AS bids are cleared.

This process effectively maximizes the qualification of SPAS, accounting for the optimal conversion of SPAS to Energy as necessary on such obligated resources

4.2.4   Other Details of SPAS

➢ The classification of SPAS resulting from the AS Self-Provision qualification process is transparent to the SC of affected Resources. Final qualification of all SPAS is reported in the publishing of IFM results, which are the end-state of the multi-step qualification process.   No information is published regarding the *conditionally qualified* or *conditionally unqualified* capacities, or the *conditionally qualified* SPAS that may have been converted to Energy in the final qualification process

➢ Self-Provided resources designated as Contingency Only are only called in the event of a Contingency, where the Contingency Flag is for the whole day. The Contingency Only designation is only applicable to real-time dispatch and does not affect the co-optimization of Energy and Ancillary Service in the Day-Ahead IFM.

➢ Self-provision of AS is not allowed from System Resources, since the cost of transmission Congestion must be considered in the Energy and AS co-optimization. System Resources can bid down to the "AS Bid floor" ($0/MWh) to ensure that they are scheduled as Price Takers.

➢ Resources may Self-Provide AS and bid in the AS market for the same service for the same hour in the same market.

4.2.5   Ancillary Service Award Allocation on Energy Bids

The market optimization applications requires an Energy Bid to be able to Dispatch any Operating Reserve awards in the RTM, irrespective of whether these awards are from qualified self-provision or accepted AS Bids, and whether they are awarded in the IFM or RTM. To effectively reserve contingent Operating Reserve from Dispatch, the RTM applications need to determine the portion of the Energy Bid that corresponds to that service so that its price is replaced with the appropriate penalty price.

Furthermore, the AS allocation on the Energy Bid is required for ex post Instructed Imbalance Energy calculation, which is by service and Energy Bid segment. This information is used in the Bid Cost Recovery and No Pay mechanisms.

Each RTM application retrieves updated Outage information from outage management system at each Dispatch time and then allocates each Ancillary Service Award onto the Energy Bid as follows:

➢ If the resource provides Regulation Up, the capacity portion equal to the Regulation Up AS Award just below the upper regulating limit or the upper operating limit (considering derates), whichever is lower, is reserved for Regulation Up. In the event of a derate, the awarded Regulation Up Capacity is shifted down. If as a result, the Regulation Up AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Up AS Award extends below the Day-Ahead Schedule (due to a derate), the Regulation Up AS Award is clipped from below to the Day-Ahead Schedule and the entire portion of the Energy Bid above the Day-Ahead Schedule is ignored.

➢ If the resource provides Regulation Down, the capacity portion equal to the Regulation Down AS Award just above the lower regulating limit or the lower operating limit

(considering overrates), whichever is higher, is reserved for Regulation Down. If the Regulation Down AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Down AS Award extends above the Day-Ahead Schedule (due to an overrate), the Regulation Down AS Award is clipped from above to the Day-Ahead Schedule and the entire portion of the Energy Bid below the Day-Ahead Schedule is ignored.

➤ If the resource provides Spinning Reserve, the Energy Bid portion equal to the Spinning Reserve AS Award below the allocated portion for Regulation Up, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever lower, is reserved for Spinning Reserve. If the total Spinning Reserve AS Award extends below the Day-Ahead Schedule (due to a derate), the total Spinning Reserve AS Award is clipped from below to the Day-Ahead Schedule.

➤ If the resource provides Non-Spinning Reserve, the Energy Bid portion equal to the Non-Spinning Reserve AS Award below the allocated portion for Regulation Up and Spinning Reserve, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever is lower, is reserved for Non-Spinning Reserve. If the total Non-Spinning Reserve AS Award extends below the Day-Ahead Schedule (due to a derate), the total Non-Spinning Reserve AS Award is clipped from below to the Day-Ahead Schedule.

➤ The remaining portion of the Energy Bid, if any, is used for Dispatch and additional AS procurement as applicable.

A Market Participant is allowed (subject to SIBR validation) to submit and designate either "Contingency Only" or "not-Contingency Only" for Spinning and Non-Spinning Reserves, for all 24 hours, according to the following rules:

➤ If Spinning Reserve is designated as Contingency Only, then Non-Spinning Reserve must also be designated as Contingency Only.

➤ If Spinning Reserve is designated as not-Contingency Only, then Non-Spinning Reserve must also be designated as not-Contingency Only.

➤ There cannot be a portion of the same service designated as Contingency Only and another portion of the same service designated as not-Contingency Only.

➤ The Contingency Flag is set for both types of AS, not for an individual service.

Exhibit 4-3 illustrates the AS Award allocation on an Energy Bid that spans the entire dispatchable capacity of a resource. Any portions of the Energy Bid for capacity allocated to Regulation Up and Regulation Down or beyond that (dashed lines in Exhibit 4-3) are ignored.

Exhibit 4-3: Ancillary Service Award Allocation on the Energy Bid
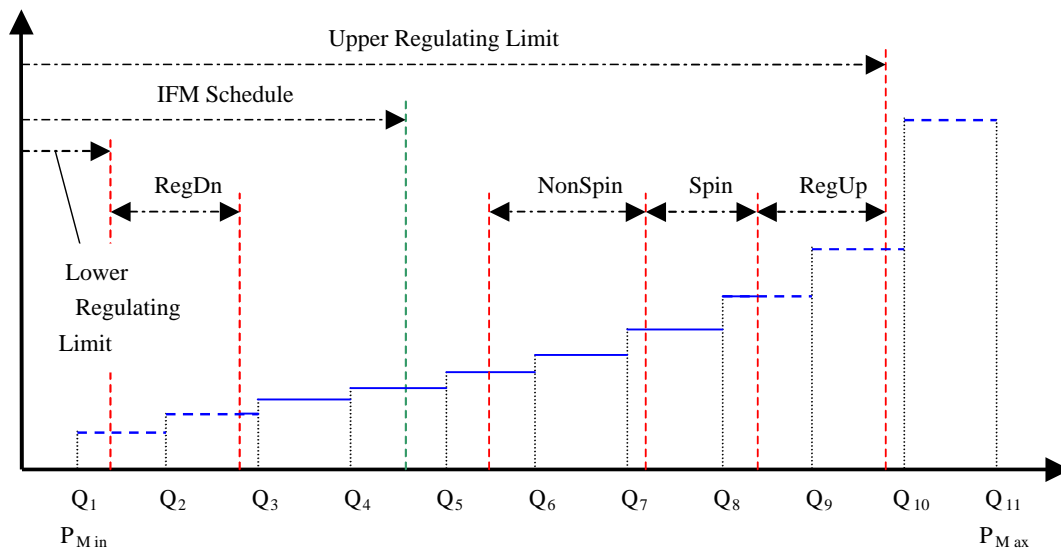
Energy Bids are required to dispatch Operating Reserve, but they are not needed for Regulation. A Regulation Up AS Award is allocated under the applicable upper regulating limit or the derated upper operating limit if lower, irrespective of whether there is an Energy Bid or not for that capacity range. Any overlapping Energy Bid portion is not used for dispatch.

The upper portion of the resource capacity from its Upper Regulating Limit is allocated to Regulation regardless of its Energy Bid Curve. This is done if the resource is awarded Regulation in the DAM or it has bid into RTM Regulation market. Regulation is not Dispatched based on its Energy Bid Curve price. Rather, Regulation is Dispatched by AGC based wholly on the resource's effectiveness to re-establish the system frequency target, and taking into consideration the resource's operating constraints, such as Ramp Rate. Also note that, AGC dispatches resources based on prices that are internally created by EMS system to coordinate control across all resources on AGC control. This coordination is necessary to ensure that AGC does not concentrate only on a few resources. This is for control not for pricing purposes.

To the extent a resource is moved away from its Dispatch Operating Point (DOP) by AGC or any uninstructed deviation, the RTM will dispatch the resource from its current output assuming that it will return to its DOP as soon as possible

To the extent that such a resource deviates from its DOP due to regulating action of AGC, the imbalance Energy produced or consumed (relative to the DOP) is attributed to Regulation and

paid as Instructed Imbalance Energy as described in Section 11.5.1. However, such imbalance Energy is not eligible for RTM Bid Cost Recovery as provided in Section 11.8.4 of the CAISO Tariff.

4.2.6   Regulation Up & Down Requirements

A minimum requirement for Regulation Up capacity and a minimum requirement for Regulation Down capacity can be specified for each AS Region and each Trading Hour. In addition, there is a Mileage requirement for Regulation Up and Regulation Down, representing the expected amount of system-wide resource operating point travel required to provide the service. Separate requirements are created for Regulation Up and Regulation Down, and are enforced at the Expanded System Region only. Finally, there is a maximum requirement for all upward AS collectively. Both Regulation Bids and Regulation self-provisions can participate in meeting these requirements. Only on-line Generating Units can be awarded Regulation service to contribute to the Regulation Up and Regulation Down requirements.

CAISO sets its Regulation reserve target as a percentage of CAISO Forecast of CAISO Demand for the hour based upon its need to meet the WECC and NERC performance standards (primarily CPS1 and CPS2). However, the percentage targets can be different for Regulation Up and Regulation Down. The percentage targets can also vary based on the hour of the Operating Day. CAISO's Regulation targets (in MWh) may change if its Demand Forecast changes after running the Day-Ahead Market.

For each hour, the Mileage procurement requirement is calculated as the lower of three values:

1) The product of each regulating service's capacity requirement and a System Mileage Multiplier for that service and hour. The System Mileage Multiplier is the amount of total expected generator movement (up or down), or Mileage, from 1 MW of Regulation Up or Down capacity. CAISO calculates an hourly System Mileage Multiplier from the measurement of Mileage of the prior 7 days for each hour. For example, if the regulation up capacity procurement target for a given hour is 350MW, and the System Mileage Up Multiplier is 3.61, the mileage procurement target would be 1263 MW (350 x 3.61).

2) The average hourly actual mileage from the prior 7 days for that hour. This is calculated as the total mileage for the relevant hour divided by 7.

3) The sum of the product of each resource's resource-specific Mileage multiplier and the resource bid-in regulation capacity. This number represents the total Mileage capability of the resources that have bid into the market. Inclusion of this number prevents a potential Mileage scarcity situation.

CAISO may adjust the mileage requirement based on operational needs.

See Appendix Attachment J for more details on the calculation of the System Mileage Multiplier and the resource-specific Mileage multiplier.

4.2.7   Operating Reserve Requirements

This section is based on CAISO Tariff Section 8.2.3.2.

CAISO sets its procurement target in accordance with WECC Minimum Operating Reliability Criteria (MORC) requirements. Currently, based on these standards, CAISO procures Operating Reserves equal to the greater of:

➢ The sum of three percent of hourly integrated load plus three percent of hourly integrated generation, or

➢ The single largest Contingency

In practice, the former (quantity of Operating Reserves based on percentage of CAISO Demand) is greater in most hours and sets the requirements system-wide. However, if CAISO must target procurement of Operating Reserves on a more granular basis, such as sub-AS Regions, the CAISO would determine the regional requirements considering the factors stated in Section 8.3.3.2 of the CAISO Tariff and discussed in Section 4.2 of this BPM. Because the single largest Contingency may affect these factors more in an AS Sub-Region than in the CAISO as a whole, the latter criteria (quantity of Operating Reserves based on the single largest Contingency) could affect the procurement of Operating Reserves in one or more of the smaller regions.

In addition, under the current standards, at least 50% of the Operating Reserve requirement must be met by Spinning Reserves,[19] and no more than 50% of the Operating Reserve requirements may be met from imports of AS.

CAISO follows these requirements or whatever other NERC or WECC standards may replace them.

Cascading is the procurement of upward AS by substituting a higher quality AS type to meet the requirement of a lower quality AS type if it is economically optimal to do so in the co-optimization process. Cascading of AS procurement does not occur in the portion of the AS

---

[19] CAISO posts a market notice in the event that the 50% Spinning Reserve requirement is to be changed.

Self-Provision Qualification Process that takes place before SCUC. The hierarchy of evaluating AS types in the cascaded AS procurement in the co-optimization process, from highest to lowest, is as follows:

- ➢ Regulation Up
- ➢ Spinning Reserve
- ➢ Non-Spinning Reserve

This substitution only occurs if the substituting resources are eligible to provide the lesser valuable service as provided in Section 8.2.3.5. Moreover, for example, if Regulation was used to meet the requirement of a lower quality AS type like Spinning Reserve, and CAISO ends up Dispatching Energy from that Capacity, the Energy will be treated as Energy from Regulation. The Regulation that was substituted from the Spinning Reserve will be settled as the need for which it was actually used, *i.e.*, the Regulation (Section 11.10.2 of the CAISO Tariff), and in addition the associated delivered Energy will be paid as Instructed Imbalance Energy (Section 11.5.1 of the CAISO Tariff) and as provided in Section 11.8.4 of the CAISO Tariff will not set LMP and will not be eligible for RTM Bid Cost Recovery.

The quantities of Regulation Up, Regulation Down, and Operating Reserves that CAISO targets for each hour of the Operating Day are published as part of the public market information by 1800 hours two days prior to the Trading Day. Total system AS requirement is also posted to OASIS.

4.2.7.1   Spinning Reserve Requirements

Separate Spinning Reserve minimal requirements are specified for each AS Region and for each Trading Hour. The Spinning Reserve requirements can be met by Spinning Reserve Bids and Spinning Reserve self-provision, as well as Regulation Up Bids. Only on-line Generating Units (and eligible System Resources) provide Spinning Reserve service. According to Ancillary Service cascading, Regulation Up can be used as Spinning Reserve after the Regulation Up requirement is met.

When cascading methodology results in awarding Regulation Up capacity to satisfy a portion of the Spinning Reserve requirement, this capacity is not treated as Spinning Reserve. The capacity retains the Regulation Up designation. As such, the Regulation Up Award does not require an Energy Bid to be dispatched in Real-Time by AGC.

4.2.7.2   Non-Spinning Reserve Requirements

Separate Non-Spinning Reserve minimum requirements can be specified for each AS Region for each Trading Hour. Bids for Regulation Up and Spinning Reserve can also be counted as

Non-Spinning Reserve. The Non-Spinning Reserve requirements can be met by Non-Spinning Reserve Bids and Non-Spinning Reserve self-provision as well as Regulation Up and Spinning Reserve Bids.

4.2.8   Maximum Upward Capacity Constraint

The total amount of upward Ancillary Service capacity may be limited for each AS Region. Specifically, the sum of Regulation Up, Spinning Reserve, and Non-Spinning Reserve procured in each AS Region using Bids or self-provision cannot exceed a maximum capacity limit at any time interval.

The purpose of enforcing a maximum procurement limit on an AS Region is to minimize the likelihood of a condition where too much AS capacity is allocated to resources in an AS Region where Energy supply limitations, due to Transmission or other constraints, are expected.

4.3   Ancillary Services Procurement

The bidding rules for AS procurement are as follows:

➢ All AS Bids (not Self-Provided) may be accompanied by an Energy Bid in DAM, and must be accompanied by an Energy Bid in RTM, which are used as the AS Bid is considered in the AS selection process (which is part of the simultaneous Energy, AS, and Congestion Market Clearing process). Only exception to this is Capacity that is awarded Regulation. Energy Bid is optional in RTM in the case of Capacity that is awarded Regulation except for MSS load-following resources. If an AS Bid in DAM is included and the Energy Bid does not extend to the full available capacity of the resource, then all or part of the AS Bid is considered to use available capacity that is not covered by the Energy Bid, and no opportunity cost is considered in the co-optimization of Energy and AS. For example, let's assume there is a resource with a Pmax of 100 MW. It provides an Energy Bid of 90 MW and AS Bid of 20 MW in DAM. The software will co-optimize until 90 MW of capacity. It will calculate if it has to use 80 MW of Energy and 20 MW of AS or 90 MW of Energy and 10 MW of AS, if it has to use this resource at all depending on the economics of the bid. Any AS Bid beyond the Energy Bid Curve has zero opportunity cost. In this case, the last 10 MW of AS bid has zero opportunity cost. See the bid curve below. The portion of the awarded AS capacity that is covered by an Energy Bid has a non-zero opportunity cost only if the total resource capacity is allocated between Energy and Ancillary Services, as would be in the case below if 80 MW of Energy were scheduled and 20 MW of spin were awarded.
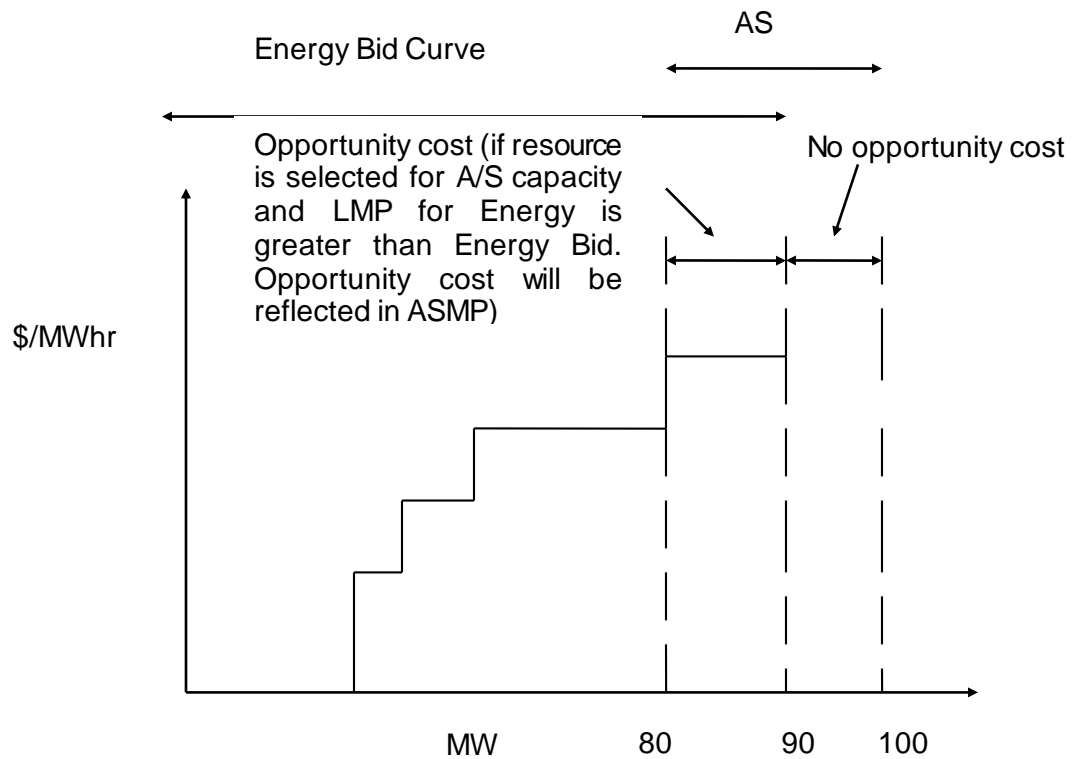
- ➢ An Energy Bid is not required for AS that is Self-Provided in the DAM. However, an Energy Bid is required in RTM for DA Spin and Non-Spin awards. While Conditionally Qualified Self-Provided AS is included in the optimization, unconditionally qualified Self-Provided AS does not enter the optimization.

The cost of procuring the AS by CAISO on behalf of the SCs is allocated to Measured Demand on a CAISO Balancing Authority Area basis.

The ISO procures Ancillary Services from Multi-Stage Generating Resources at the MSG Configuration level.

4.3.1   Ancillary Services Procurement in Day-Ahead Market

CAISO procures 100% of its AS needs associated with the CAISO Forecast of CAISO Demand net of unconditionally qualified Self-Provided AS. AS Bids are evaluated simultaneously with Energy Bids in the IFM to clear bid-in Supply and Demand. Thus, the IFM co-optimizes Energy and AS; the capacity of a resource with Energy and AS Bids is optimally used for an Energy schedule, or it is reserved for AS in the form of AS Awards. Furthermore, AS Bids from System Resources compete with Energy Bids for intertie transmission capacity.

Energy Schedules and AS Awards from System Resources are constrained over Interties. Therefore, the optimal Dispatch of Energy and AS capacity can be accomplished by assigning the same Congestion cost to each commodity. This process allows Energy and AS capacity to compete for the transmission access to (or from) the CAISO Balancing Authority Area directly, based on their Bids. This cannot be done for transmission internal to the CAISO Balancing Authority Area because the particular use of Ancillary Services in RTM is unknown during the AS procurement process. For this reason, Energy and AS capacity cannot directly compete for transmission across the internal CAISO Balancing Authority Area grid.

In the optimization of Energy and AS clearing, the limits on AS Regions are enforced as constraints represented by penalty prices in the application software, while Energy and AS are economically optimized subject to the AS Region procurement constraint(s).

AS are procured in the IFM to meet the AS requirements, net of qualified AS self-provision, subject to resource operating characteristics and regional constraints.

For Regulation Up and Regulation Down, Capacity and Opportunity Cost Bids are combined into a single bid which is co-optimized with Energy, Mileage, and other Ancillary Services. Additional constraints are added in the optimization problem to limit the Mileage awards for each resource with regulation capacity awards within a range based on the respective resource mileage multiplier. If economical, the optimization may procure Regulation from resources more likely to provide Mileage, i.e. have a higher resource Mileage multiplier, in order to meet the Mileage requirement.   However, in general the optimization will not procure additional Regulation capacity in order to meet the Mileage requirement.

Because intertie transmission capacity must be reserved for AS Import Awards, AS Import Awards are charged with explicit Congestion charges when the relevant intertie is congested. For Energy Schedules, Congestion charges are included in the LMPs. However the ASMPs do not reflect congestion. For this reason, AS imports are charged with a separate Congestion charge that amounts to the AS Import Award multiplied by the shadow price of the relevant congested intertie. Regulation Up, Spinning Reserve and Non-Spinning Reserve are charged

when the relevant intertie is congested in the import direction, whereas Regulation Down is charged when the relevant intertie is congested in the export direction. Unlike Energy imports and exports, AS imports are not paid when the relevant intertie is congested in the opposite direction because they do not create counter flow intertie transmission capacity.

Absent binding inter-temporal constraints (such as block energy constraints), the ASMP for a given AS and Import Resource minus the shadow price of the relevant intertie (in the appropriate direction) would be no less than the accepted AS bid price plus any opportunity cost.

Unlike other AS Awards, the Mileage procurement for Regulation Up and Regulation Down is not a financially binding award. Resources will be settled based on Adjusted Instructed Mileage as adjusted for accuracy. See the *BPM for Settlements and Billing* for more information.

4.3.2   Ancillary Services Procured in Real-Time

➢ Ancillary Services are procured in the Real-Time Market from resources internal to the ISO system and System Resources that do not submit HASP Block Intertie Schedules, through the FMM process, as needed to satisfy the NERC requirements. []

➢ Ancillary Services are procured on an hourly basis in the HASP from Non-Dynamic System Resources that submit Hourly Block Bids.

Ancillary Services Awards for all resources except Non-Dynamic System Resources that submit Hourly Block Bids are only considered binding the first 15-minute interval of each FMM run. Ancillary Service Awards from Non-Dynamic System Resources that submit Hourly Block Bids that are procured in the HASP are considered binding for the HASP Trading Hour. The resources that are committed in Real-Time to provide Imbalance Energy and/or AS are eligible for Start-Up and Minimum Load Cost compensation, except for Non-Resource Specific System Resources.

Additional AS are procured in Real-Time only from resources that are certified to provide these services.

Refer to Section 7.6.2, Real-Time Ancillary Services Procurement, for additional information.

4.3.2.1   Regulation

CAISO can procure Regulation in RTM from resources which are available and offer Regulation and Mileage bids in RTM. WECC allows Regulation to be used for Spinning Reserve. Although Regulation Up won't necessarily be used as spin, it does count to ensure that there are sufficient Operating Reserves available.

4.3.2.2   Spinning & Non-Spinning Reserve

This section is based on CAISO Tariff Section 31.5.6.

Real-Time procurement and pricing of Spinning Reserve and Non-Spinning Reserve is performed using dynamic co-optimization of Energy and Spinning and Non-Spinning Reserve. Spinning Reserve and Non-Spinning Reserve procured in Real-Time are for Contingency Only.

These requirements are calculated as part of the RTM based on the Demand Forecast and can be adjusted by the CAISO Operator.

4.4   Ancillary Services Marginal Prices

Generally speaking, the Ancillary Services Marginal Price (ASMP) for a given service at a given "location" is the cost of procuring an increment (MW) of that service at that location. It is, however, understood that the use of the word "location" here is not entirely precise because the "locations" where AS requirements are defined are AS Regions, whereas ASMPs are determined for individual PNodes.

This is a somewhat academic distinction, however, because in practice all PNodes belonging to the same set of AS Regions have the same ASMP. To better understand this statement, consider the AS Expanded System Region along with all of the AS Regions. Because some AS Regions have common areas (are nested), collectively they divide up the AS Expanded System Region into smaller areas. The ASMP for all PNodes within each of these smaller areas is the same.

ASMPs can be described more precisely in terms of Regional Ancillary Service Shadow Prices (RASSPs). RASSPs are produced as a result of the co-optimization of Energy and AS for each AS Region, and represent the cost sensitivity of the relevant binding regional constraint at the optimal solution, i.e., the marginal reduction of the combined Energy-AS procurement cost associated with a marginal relaxation of that constraint.

The opportunity cost for a resource which is awarded AS rather than energy when the energy bid is otherwise competitive is not computed explicitly, rather it is implicit in RASSP for that AS Region.

If neither of the constraints (upper or lower bound) is binding for an AS Region, then the corresponding RASSP is zero. The ASMP for a given service at a particular PNode is the sum of all RASSPs for that service over all AS Regions that include that PNode. It thus follows that all PNodes located in exactly the same set of AS Regions have the same ASMP. For example, if the defined AS Regions with non-zero RASSPs consist of "South of Path 26", the System

Region, the Scheduling Points, and the Expanded System Region, then all resources within "South of Path 26" have the same ASMP.

Exhibit 4-4 presents an example of how the RASSPs and ASMPs are related for a given set of the AS Regions. In this example the RASSPs are "given" from a pricing run for a specific AS product. The resulting ASMPs are for the PNodes within each AS Region.

Exhibit 4-4: Example for Spinning Reserve AS

AS Region	RASSP (Given)	ASMP @ PNode
South of Path 26	$20/ MW	20 + 10 + 5 = $35/MWh
System	$10/ MW	10 + 5 = $15/MWh
Expanded System	$5/ MW	$5/MWh

ASMP reflects any lost opportunity costs associated with keeping the resource capacity unloaded for AS instead of scheduling that capacity as Energy in the same market when the entire available capacity of a given resource is totally allocated among Energy and AS Awards.

Regulation Up and Regulation Down Mileage Marginal Prices are published for the Expanded System Region only, since the Mileage requirements are set only for the Expanded System Region.

4.4.1   Ancillary Services Pricing in Event of Supply Insufficiency

In the event that supply is insufficient to meet the minimum reserves procurement requirements in Ancillary Service Region or Sub-region, the scarcity pricing mechanism lets Ancillary Service Marginal Prices in the scarce Region or Sub-region rise automatically to administratively determined values. The mechanism uses a Scarcity Reserve Demand Curve with different pre-determined values at different levels of scarcity. If minimum Ancillary Service requirements of the Expanded System Region and/or Ancillary Service Sub-Regions are not met, the Ancillary Service Shadow Prices corresponding to the supply deficient Ancillary Services in Expanded System Region or Ancillary Service Sub-Region will rise to the Scarcity Reserve Demand Curve Values that reflect the level of shortage. The Ancillary Service Marginal Price of a higher quality reserve will always be higher than or equal to the price of a lower quality reserve in the same Ancillary Service Region or Sub-region. Also, the Ancillary Service Marginal Price of a reserve in a sub-region will always be higher than or equal to the price of the same reserve in the outer sub-region or Expanded System Region. The CAISO will consider the System Region as a Sub-Region for the purposes of Ancillary Service pricing in case of supply insufficiency.

4.4.1.1   Scarcity Reserve Demand Curve

The CAISO will use Scarcity Reserve Demand Curves to set the administrative values for Ancillary Service Marginal Prices in supply shortage conditions. The CAISO will use a tiered demand curve for the three upward reserves i.e. Spinning Reserve, Non-Spinning Reserve and Regulation Up Service and a separate tiered demand curve for Regulation Down Service. The CAISO defines Scarcity Reserve Demand Curve Values, as shown in the exhibit below, as percentages of the maximum energy bid price set forth in Tariff Section 39.6.1.1:

Exhibit 4-5: Scarcity Reserve Demand Curve Values

Reserve	Demand Curve Value ($/MWh)					
	Percent of Max Energy Bid Price		Max Energy Bid Price = $750/MWh		Max Energy Bid Price = $1000/MWh	
	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region
Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & < = 210 MW	60%	60%	$450	$450	$600	$600
Shortage ☐ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1,000**	**$1,000**
Regulation Down Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & < ☐ 84 MW	60%	60%	$450	$450	$600	$600
Shortage ☐ 32 MW	50%	50%	$375	$375	$500	$500

4.4.1.2   Ancillary Services Sub-Regional Partitions

According to the CAISO tariff, the Scarcity Reserve Demand Curve Value will not be double-counted in the calculation of Ancillary Service Marginal Prices when there is scarcity in a sub-

region. For that purpose the CAISO will enact Ancillary Service sub-regional partitions when there is Ancillary Service scarcity in one or more Ancillary Service Sub-Regions.

For example, all internal resources in SP-26 are contained in SP_26_Expanded as well as the CAISO (not CAISO_Expanded) Ancillary Service sub-regions. However, the intertie resources in SP_26_Expanded are not part of the CAISO Ancillary Service Sub-Region. Instead, they are part of the CAISO Expanded System Region. This situation creates overlapping (not total nesting) of Ancillary Service Sub-Regions. When scarcity occurs in the scheduling run in SP_26, the CAISO will separate SP_26 from SP_26_Expand to form two partitions: SP_26_Part, which is the geographic footprint of SP_26 Sub-region and SP_26_Expand_Part, which is the part of SP_26_Expand not overlapping with SP_26. The CAISO will also separate SP_26_Part from the CAISO Sub-region to create another partition CAISO_Part, which is the part of CAISO that does not overlap with SP_26.

The CAISO will use non-overlapping Ancillary Service partitions to establish Ancillary Service procurement requirements. The following figure provides an illustration of the partition concept using the SP_26, SP_26_Expanded and CAISO System Regions.

Non-Overlapping Partitions of the Ancillary Service Sub-Regions
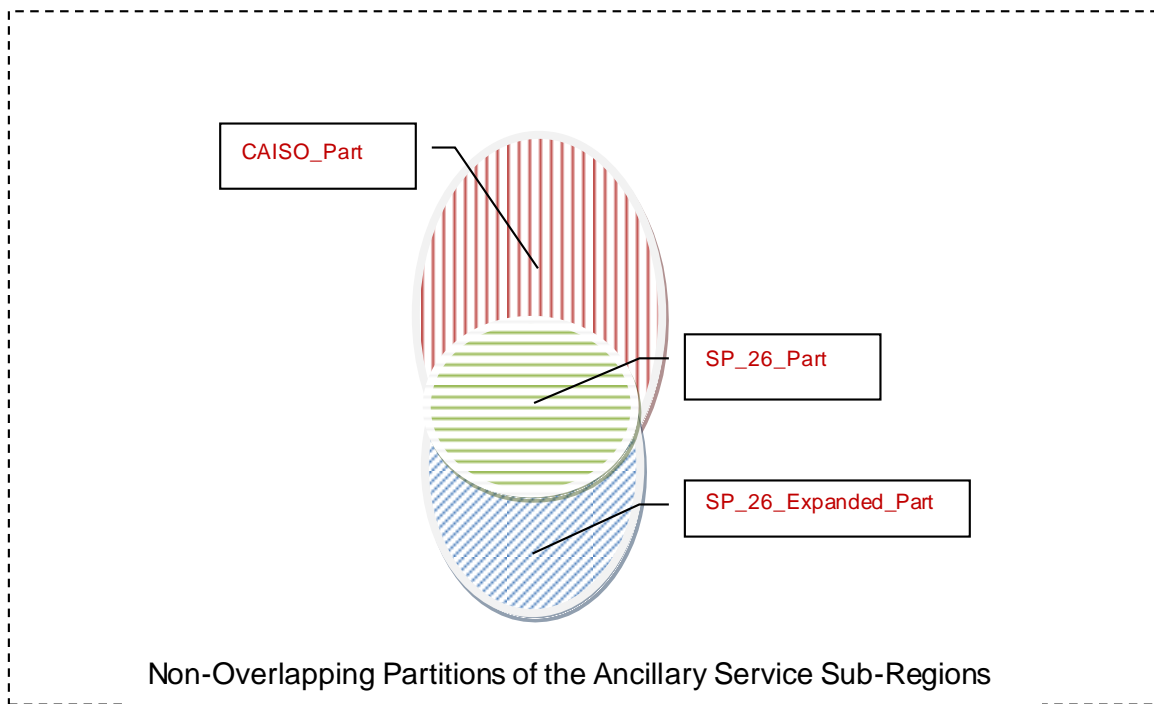
The ISO calculates Ancillary Service Marginal Prices in a Sub-Region as the sum of shadow prices of Ancillary Service procurement requirement constraint in the Sub-Region and the Region in which the Sub-Region nests. To make this calculation explicit to market participants, the CAISO may adjust the calculated Ancillary Service Shadow Prices of the scarce sub-region partitions and publish the adjusted shadow prices on the CAISO OASIS.

The published pricing run adjusted Shadow Prices, λ_{adj}, for each of the Ancillary Service reserves in the scarce Ancillary Service partition shall be calculated as the maximum of zero, and the difference between the Shadow Price of the Ancillary Service reserve in the scarce partition and the Shadow Price of the same Ancillary Service reserve in the CAISO_Expand constraint, i.e. $\lambda^{adj}_{partition,As} = \max(0, \lambda_{partition,AS} - \lambda_{system,AS})$. The adjusted Shadow Prices shall be used for the calculation of the resources' Ancillary Service Marginal Prices. The calculations of the Ancillary Service Marginal Price on a resource level will continue to follow the same calculation rule of summing all Shadow Prices for all Ancillary Service constraints (whether Ancillary

Service region/sub-region or Ancillary Service partition) in which the resource is participating. For example, resources in the SP_26 Ancillary Service Sub-Region participate in the SP_26 Ancillary Service Sub-Region, the CAISO System Region, and SP_26_Part Ancillary Service partition, but not in the CAISO_Part Ancillary Service partition constraint nor in SP_26_Expanded_Part Ancillary Service partition constraint.

4.4.1.3   Examples of Ancillary Service Marginal Price calculation

This section provides examples of calculating Ancillary Service Marginal Prices in a supply insufficiency situation. For the purpose of these examples, it is assumed that there is only one Ancillary Services Sub-Region which is nested within the Expanded System Region. These examples reflect various scenarios from the shortage of one reserve in the Expanded System Region to shortage of all Ancillary Services in Expanded System Region and Sub-Region. Some of the scenarios are unlikely to occur in actual market operation. They are provided in this document to illustrate how the ISO will calculate Ancillary Service Marginal Prices when a scarcity condition occurs. The Ancillary Service shadow prices in the scarce sub-regions and partitions are adjusted based on the method described in section 4.4.1.2 of this document.

Example 1:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Non-Spinning Reserve greater than 210 MW in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Expanded System Region is $700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves in the Expanded System Region and sub-region are shown in the exhibit below.

Please note that the Ancillary Service Marginal Prices of all three Ancillary Services in the Sub-Region are above the $700/MWh scarcity price in the Expanded System Region. In this example, the Ancillary Service Marginal Prices reflect the opportunity cost of providing energy by the resources in the Sub-Region in addition to the scarcity condition in the Expanded System Region.

Exhibit 4-6: Ancillary Service Marginal Prices in the case of Non-Spinning Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	700	90	700	790
Spinning	700	50	700	750
Non-Spinning	700	30	700	730
Regulation Down	30		30	

Example 2:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Non-Spinning Reserve greater than 210 MW in the Ancillary Services Sub-Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Sub-Region will be $ 700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-7: Ancillary Service Marginal Prices in the case of Non – Spinning Reserve shortage in the Ancillary Services Sub-Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	150	550	150	700
Spinning	60	640	60	700
Non-Spinning	50	650	50	700
Regulation Down	30		30	

Example 3:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage in Regulation-Up Reserve in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Regulation-Up Reserve in the Expanded System Region will be $200/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves shown in the exhibit below.

Exhibit 4-8: Ancillary Service Marginal Prices in the case of Regulation-Up Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	200	90	200	290
Spinning	60	50	60	110
Non-Spinning	50	30	50	80
Regulation Down	30		30	

Example 4:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage greater than 210 MW of Non-Spinning Reserve and a shortage in Regulation-Up shortage in the Expanded System Region when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Price for Regulation-Up in the Expanded System Region will be $200/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. In this example, the Ancillary Service Shadow Price for Non-Spinning Reserve in the Expanded System Region is $700/MWh, determined by the demand curve value with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-9: Ancillary Service Marginal Prices in the case of Regulation-Up Reserve and Non-Spinning Reserve shortage in the Expanded System Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	900	90	900	990
Spinning	700	50	700	750
Non-Spinning	700	30	700	730
Regulation Down	30		30	

Example 5:

This example demonstrates the calculation of Ancillary Service Marginal Prices for various reserves in case of a shortage of all Reserves in both Expanded System Region and Sub-Region when the Non-Spinning Reserve shortage in the Expanded System Region is greater than 210 MWs and the Regulation Down shortage is greater than 84 MWs when the maximum energy bid price is $1,000/MWh. In this example, the Ancillary Service Shadow Prices for all reserves are determined by the demand curve values with $1000/MWh maximum energy bid price. The Ancillary Service Marginal Prices for all reserves are shown in the exhibit below.

Exhibit 4-10: Ancillary Service Marginal Prices in the case of shortage of all Reserves in both Expanded System Region and Sub-Region

Reserve	Ancillary Service Shadow Price ($/MWh)		Ancillary Service Marginal Price ($/MWh)	
	Expanded System Region	Sub-Region	Resources participating in Expanded System Region but not in Sub-Region	Resources participating in Sub-Region
Regulation Up	1000	0	1000	1000
Spinning	800	0	800	800
Non-Spinning	700	0	700	700
Regulation Down	700		700	

4.4.1.4   Impact on Energy Price

In a situation of Ancillary Service supply shortage, Ancillary Service shadow prices will be set by the Scarcity Reserve Demand Curve Values. The energy prices may either rise together with the Ancillary Service prices, or may be unaffected by the increase in Ancillary Service prices. If a generating unit backs down its schedule of an Ancillary Service that is scarce in order to provide one additional MW of energy, the price of energy will include the opportunity cost of the scarce capacity, i.e. the shadow price of the Ancillary Service constraint set by the Scarcity Reserve Demand Curve Value, as well as the bid price of the incremental energy.

4.4.1.5   Ancillary Service Supply Insufficiency Notification

The ISO will issue a Market Notice to inform Market Participants if a scarcity condition occurs.

4.5   Ancillary Services Considerations

This section identifies important considerations in the use and procurement of Ancillary Services, including:

➢ The Operating Reserve Ramp Rate for Energy within the AS capacity is a single Ramp Rate, which is distinct from the Operational Ramp Rate, and is the same for Spinning and Non-Spinning Reserve.

➢ Energy Limits of resources bidding into the AS market can be managed by the use of the Contingency Only designation supplied by the SC in the AS Bid. The Contingency Only designation applies for the entire Trading Day. In Real-Time, Energy from Contingency Only Operating Reserves is only cleared against Demand only under Contingency situations.

➢ Day-Ahead SC trades of Ancillary Service Obligations are supported; however, physical trades of Ancillary Services capacity is not.

➢ Day-Ahead SC trades of Ancillary Service Obligations are supported; however, physical trades of Ancillary Services capacity is not.

➢ Forbidden Operating Regions may limit the procurement of Ancillary Services. Specifically, the procurement of Regulation Up, Spinning Reserve, and Non-Spinning Reserve may be limited by the lower bound of a Forbidden Operating Region, and the procurement of Regulation Down may be limited by the upper bound of a Forbidden Operating Region. For the hourly DAM AS procurement, a resource must be able to cross its FOR within 20 minutes in order to be eligible to provide AS for that Trading Hour. For RTM AS procurement, unless a resource can complete the crossing of its FOR within the relevant 15 minute interval, it is ineligible to provide AS and will thus not be called upon to provide AS for that interval., .

➢ Ancillary Services are not procured from Multi-Stage Generating Resources during a transition between MSG Configurations in both the Day-Ahead Market and Real-Time Market. Also, during the period in which the FMM determines that a Multi-Stage Generating Resource is in transition from one configuration to another, any Day-Ahead Ancillary Service Award or Real-Time Self-Provided Ancillary Services will be disqualified. To determine the exact transition period, the Transition Time adheres to the following rounding method:

1. Day-Ahead Market--Transition Time of any resource with a value of X hours plus 7.5 minutes or more will be rounded to X+1 hours and any Transition Time of X hours plus less than 7.5 minutes will be rounded to X hours;

2. Real-Time Unit Commitment--Transition Time of any Multi-Stage Generating Resource with a value of X number of 15 minute intervals plus 7.5 minutes or more will be rounded to X+1 number of 15 minute intervals and any Transition Time of X number of 15 minute intervals plus less than 7.5 minutes will be rounded to X number of 15 minute intervals;

3. Real-Time Dispatch--Transition Time of any Multi-Stage Generating Resource will use the rounded transition time from RTUC.

➢ Bids to export AS are not supported in the CAISO Markets.

➢ Export of on-demand obligations of AS are manually supported but cannot be procured from the DAM or RTM.

➢ All Spinning and Non-Spinning Reserves awarded in the RTM are automatically classified as Contingency Only. Furthermore, any DA Spinning and Non-Spinning Reserve Awards are re-classified as Contingency Only if additional Spinning or Non-Spinning Reserve is awarded in RTM. See CAISO Tariff Section 34.2.2. Any Spinning and Non-Spinning Reserve procured from Non-Dyanmic System Resources are also considered contingency only.

➢ Any AS designated as Contingency Only is not normally dispatched as Energy in the normal RTED mode. In the Real Time Contingent Dispatch (RTCD) mode, Energy behind Contingency Only AS and non-Contingency Only AS is not distinguished, and is dispatched economically.

➢ Contingency Only Reserves can also be dispatched by RTED under special circumstances. Section 34.3.2 and 34.8 of the CAISO tariff stipulates the conditions under which the CAISO can dispatch Contingency-Only Reserves.

➢ Scheduling Coordinators are required to submit an Energy Bid for Non-Dynamic System Resources submitting an Ancillary Services bid in the Real-Time Market. However, the CAISO will only use the Ancillary Service Bid in solving the optimization problem and the associated Energy Bids will not be used in the RTM. The ISO will, therefore, not Dispatch any Energy from the associated Energy Bid if there is no Ancillary Services awarded to the Non-Dynamic System Resource. If the Scheduling Coordinator fails to submit an Energy bid with an Ancillary Services Award, the ISO will generate an Energy bid for the associated Ancillary Services Bid and will not use such Energy bid to Dispatch Energy.   See CAISO Tariff Section 30.5.2.6 and the BPM for Market Instruments.

4.6   Ancillary Services Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements, and Section 8.4, Technical Requirements for Providing Ancillary Services

Each Generating Unit, System Unit, or Load and PDRs that are allowed to submit a Bid or AS self-provision under the CAISO Tariff, and each System Resource that is allowed to submit a Bid to provide AS under the CAISO Tariff, must comply with CAISO's certification and testing requirements as contained in the *BPM for Compliance Monitoring*.

RDRR resources are not allowed to provide Ancillary Services.

The CAISO certifies Multi-Stage Generating Resources for Ancillary Services at the MSG Configuration level.

CAISO has the right to inspect Generating Units, Participating Loads and PDRs, or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that the technical requirements continue to be met. If at any time CAISO's technical requirements are not being met, CAISO may withdraw the certificate for the Generating Unit, System Unit, Participating Load, PDRs or System Resource concerned.[20]

The AS certification and the associated maximum AS capacity are registered in the Master File after testing that demonstrates satisfactory delivery of each AS.

4.6.1   Regulation Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.1.1.

Each Generating Unit and System Unit that submits a Bid Regulation or Self-Provides Regulation must be certified and tested by CAISO using the process defined in Part A of Appendix K of the CAISO Tariff. Each Dynamic System Resource offering Regulation must comply with the Dynamic Scheduling Protocol in Appendix M of the CAISO Tariff.

Generating Units with Automatic Generation Control capability may be certified for Regulation Up and Regulation Down. Their maximum Regulation Up and Regulation Down capacity is limited to their 10-minute Ramping capability with their best Regulation Ramp Rate.

A resource may lose its ability to provide Regulation if its performance falls below a minimum performance threshold for Regulation Up or Regulation Down. If a resource's measured accuracy, based on a weighted average of fifteen minute intervals during a calendar month

---

[20] Participating Generators, Participating Loads and Dynamically-Scheduled System Resources are governed by pro-forma Agreements that are included as Appendix B of the Tariff. Each of these Agreements has a Termination clause that permits cancellation of the Agreement under certain conditions, including failure to meet technical requirements. See, for example, Section 3.2.1 of the Participating Generator Agreement.

using Instructed Mileage as the weight, is less than twenty five percent for Regulation Up or Regulation Down, the CAISO will provide notice to the resource's Scheduling Coordinator of the resource's failure to meet the minimum performance threshold after the end of the calendar quarter in which the performance failure occurred. Calendar quarter is defined as the periods January-March, April-June, July-September, and October-December. The resource must re-certify to provide the respective service within ninety days from the date of the notice. In the event of lost accuracy data, the CAISO will not use data from these intervals to calculate the resource's Historic Regulation Performance Accuracy or to assess the minimum performance threshold.

Resource-specific System Resources may also be certified for Regulation Up and Regulation Down. Such units must have AGC and dynamic interchange capability to provide Regulation.

Non-generator resources selecting Regulation Energy Management may also be certified for Regulation Up and Regulation down. Using Regulation Energy Management, a NGR maximum Regulation Up and Regulation Down capacity is based on four (4) times the maximum Energy (MWh) the resource can generate or consume for fifteen (15) minutes after issuance of a Dispatch Instruction. Otherwise NGRs selecting Regulation Energy Management must meet the same certification requirements as generators.

For example:

> 1.   A fully charged resource with 5 MWh of energy storage can continuously discharge a maximum 20 MW to the grid for 15 minutes to reach a zero (0) state of charge. If there are no other limitations, the resource will be certified for 20 MW of regulation up capacity. This 20 MW represents four (4) times the 5 MWh discharged in fifteen (15) minutes.

> 2.   A completely discharged resource with 2.5 MWh of energy storage can continuously consume a maximum 10 MW from the grid for 15 minutes to reach a full state of charge. If there are no other limitations, the resource will be certified for 10 MW of regulation down capacity. This 10 MW represents four (4) times the 2.5 MWh consumed in fifteen (15) minutes.

NGRs electing not to use Regulation energy Management will be certified the same as generators.

4.6.2   Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards

Spinning Reserve may be provided only from Generating Units and System Resources that submit Bids to provide Spinning Reserve from imports, or System Units, which are certified and tested by CAISO using the process defined in Appendix K of the CAISO Tariff.

Dispatchable Generating Units may be certified for Spinning Reserve if they can respond to five-minute Dispatch Instructions. Their maximum Spinning Reserve capacity is limited to their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower.

4.6.3   Non-Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards.

Non-Spinning Reserve may be provided from Participating Loads, PDRs and Curtailable Demand which can be reduced by Dispatch, interruptible exports, on-demand rights from other entities or Balancing Authority Areas, Generating Units, System Resources that submit Bids to provide Non-Spinning Reserve from imports, or System Units, which have been certified and tested by CAISO using the process defined in – Parts C of Appendix K of the CAISO Tariff, respectively.

Generating Units may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions.

➢ The maximum Non-Spinning Reserve capacity for Fast Start Units that can start and synchronize with the grid within 10 minutes are limited to the output level they can reach from offline status in 10 minutes, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is higher, but not greater than their maximum capacity.

➢ The maximum Non-Spinning Reserve capacity for other resources that cannot start and synchronize with the grid within 10 minutes are limited to their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower. In the IFM, Non-Spinning Reserve can be procured from all on-line resources (whether self-committed or committed in the IFM) and from offline Fast Start Units.

Only units whose technical characteristics allow them to deliver Non-Spinning Reserve Award within 10 minutes may submit a Bid for Non-Spinning Reserve into RTM.

Units that are already on-line may also offer Non-Spinning Reserve, provided that they are otherwise eligible. However, they may be awarded non-spin only after they shut down.

Participating Load resources may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain reduced Energy consumption associated with a Non-Spinning Reserve Award for at least thirty minutes.

5. Existing Transmission Contracts, Converted Rights & Transmission Ownership Rights

Welcome to the *Existing Transmission Contracts, Converted Rights, & Transmission Ownership Rights* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

➢ A description of the rights and obligations of Non-Participating TOs and PTOs for Existing Rights for transmission under CAISO Operational Control

➢ How CAISO uses the Existing Transmission Contract Calculator (ETCC)

➢ The interaction between Transmission Ownership Rights (TORs) in the CAISO Balancing Authority Area and the CAISO

➢ There are three types of transmission rights in general:

- Existing Transmission Contracts (ETCs)

- Converted Rights (CVRs)

- Transmission ownership rights (TORs)

5.1 Continuation of Rights & Obligations

5.1.1 Existing Transmission Contracts

Existing Transmission Contracts (ETCs) are contractual agreements established prior to the creation of CAISO by which a PTO is obligated to provide transmission service to another party, using transmission facilities owned by the PTO that have been turned over to CAISO Operational Control. An Encumbrance is an Existing Right that an entity, other than a PTO, has on the CAISO Controlled Grid. (CAISO Tariff § 16).

ETCs were created prior to March 31, 1998, when one party to the contract, the PTO, both owned and operated their portion of the transmission grid. After the CAISO became operational, PTOs continue to own their respective portions of the transmission grid but the CAISO is now responsible for the operations of the transmission facilities for which the PTOs transferred their control to the CAISO, including their Entitlements and Encumbrances as defined in the CAISO Tariff and the Transmission Control Agreement Among the Independent System Operator and Transmission Owners, California Independent System Operator Corporation, FERC Electric Tariff No. 7 ("Transmission Control Agreement"). Entitlements consist of those rights on

transmission facilities owned by another entity that the Participating Transmission Owners have obtained by contract or other means to use for their transmission of Energy and Ancillary Services. The cost for transmission service provided under the ETC was negotiated and agreed upon by both parties to the ETC, and then embedded in the terms and conditions of these contracts. The CAISO is not a party to the ETCs. Thus, when CAISO became the transmission operator for the PTO's transmission facilities, the transmission service component of these pre-existing contractual arrangements are honored by granting holders of Existing Rights unique operational and Settlement arrangement, such as the reservation of transmission capacity and exemption from the Access Charge and Congestion Charge associated with such transmission service.

5.1.2   Converted Rights

Converted Rights are transmission rights that are obtained by a party to an ETC that chooses to become a Participating TO and convert its rights to CAISO transmission service. (CAISO Tariff § 4.3.1.6) In the event of such conversion, the Participating TO that is party to the ETC is required to change the terms and conditions of the ETC to provide that:

1) The previously Existing Rights holder under the contract turns over the management of its transmission Entitlement to the CAISO pursuant to the CAISO Tariff and the TCA;

2) The previously Existing Rights holder has converted its rights to CAISO transmission service and shall obtain all service on the CAISO Controlled Grid per the CAISO Tariff;

3) The previously Existing Rights holder shall be entitled to receive the contract cost for the Converted Right in its Transmission Revenue Requirement along with all Wheeling revenue credits throughout the term that the capacity is available under the Existing Contract for the capacity represented by its rights;

4) The previously Existing Rights holder, shall continue to have the obligation to pay the provider of the service for its transmission service at the rates provided in the Existing Contract, as they may change from time to time under the terms of the Existing Contract, or as mutually agreed between the contract parties, through the term of the contract, subject to the terms and conditions of the contract, including the rights of the parties to the contract to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

Such previously Existing Rights holders are New Participating TOs that have joined the CAISO and turned over the Operational Control of their facilities and Entitlements to the CAISO. Until December 31, 2010, such entities shall be entitled to receive the IFM Congestion Credit as provided in Section 11.2.1.5 of the CAISO Tariff. In the event that the rights are derived from an ETC with an Original Participating TO, the New Participating TO and the applicable Original PTO shall work together to submit the TRTC Instructions. (CAISO Tariff § 4.3.1.2.1)

CVRs are treated in the same manner with respect to scheduling, scheduling priority and settlement in the Day-Ahead Market. CVRs do not receive any special rights in the Real-Time Market in terms of scheduling priority or the reversal of Congestion Charges.

5.1.3   Non-Participating Transmission Owners

The transmission service rights and obligations of Non-Participating Transmission Owners ("Non-Participating TOs") under ETCs, including all terms, conditions and rates of the ETCs, as they may change from time to time in accordance with the terms and conditions of the ETCs, continue to be honored by CAISO and the parties to those contracts, for the duration of those contracts.

In addition, some Non-Participating TOs have Transmission Ownership Rights (TORs) that represent transmission capacity on facilities that are located within the CAISO Balancing Authority Area that are either wholly or partially own by the Non-Participating TO.

5.1.4   Transmission Ownership Rights

Transmission Ownership rights are rights that accrue either through ownership or joint-ownership of transmission facilities that are situated within the CAISO Balancing Authority Area but are not incorporated into the CAISO Controlled Grid because the Non-Participating Transmission Owners of such rights have not executed a Transmission Control Agreement.

In operating the DAM and the RTM CAISO accounts for the Transmission Ownership Right (TOR) capacity as follows:

➢ For TOR capacity on interties that are in the FNM, the CAISO reduces the available quantity scheduling rights at the intertie by the amount of the TOR.

➢ For TOR capacity that is internal to the CAISO Balancing Authority Area and modeled as part of the looped network, CAISO does not set aside capacity on the facility, but instead provides highest priority source-to-sink scheduling rights to the TOR holder. The source and sink points for such scheduling rights are determined by the TOR holder and

CAISO, consistent with the TOR holder's rights, in a manner that ensures the ability of the TOR holder to fully utilize its rights.

➢ TORs are not entitled to CRR payments, the balance of any CRR accounts or the Access Charges, but are settled under the "perfect hedge" in accordance with Sections 11.2.1.5 and 11.5.7 of the CAISO Tariff for transactions on their TOR systems.

In implementation and allocation of CRRs, the appropriate TOR capacity is removed from the FNM prior to running the CRR Allocation and CRR Auction markets by using Point-to-Point CRR Options. These Point-to-Point CRR Options will be held by the CAISO. Refer to Attachment B, section 4, of the BPM for CRRs for more information on this process.

TOR capacity reservations (i.e., the differences between TOR entitlements and TOR Self-Schedules) are made only on intertie. The CAISO will reserve unused TOR and make a corresponding adjustment in its determination of ATC (CAISO Tariff § 17.2)

The Non-Participating TO with a TOR works with the CAISO to develop any Transmission Rights and Transmission Curtailment (TRTC) Instructions required. The TRTC Instructions provided to CAISO to decide which Scheduling Point TOR has reservation requirements in which markets. Such instructions are part of the look-up tables or formulas for calculating the TOR. No TOR reservation is made in the DAM and RTM unless explicit instructions for reservation by markets are provided to CAISO.

5.1.5   TOR Scheduling Time Line Requirements

The TOR scheduling time line requirements specifies the latest time that an SC may submit TOR Self-Schedules and receive scheduling priority. Validation of the use of TORs is based on resource specific information. If a specific System Resource must be associated with certain TOR to be hedged from congestion, it is the responsibility of the Non-Participating TO to identify all possible sources and sinks eligible to utilize the TOR. The *BPM for Market Instruments* describes the scheduling process in more detail.

The following timeline applies to TOR Self-Schedules:

➢ In DAM, the SC must submit its TOR Self-Schedule by the close of the DAM (1000 hours) for its TOR. If the SC does not schedule all of its TOR, then transmission at an Intertie is reserved for the unused TOR amount in the RTM for that Intertie.

➢ In the RTM, the SC must submit TOR Self-Schedules by the close of the RTM (T-75 minutes) if the transmission right is for capacity on the transmission path at a Scheduling Point.

➢ In HASP, CAISO re-dispatches non-TOR or non-ETC resources to accommodate valid TOR Self-Schedule changes that are not at an Intertie in HASP provided the TRTC Instruction explicitly allows for such a scheduling right.

➢ In FMM, CAISO re-dispatches non-TOR or non-ETC resources to accommodate valid TOR Self-Schedule changes in Real-Time provided the TRTC Instruction explicitly allows for such a scheduling right.

➢ For TOR Self-Schedule changes between 75 minutes and 20 minutes prior to the Operating Hour, the relevant SC may schedule any remaining transmission rights by calling the CAISO Operator to input an Exceptional Dispatch in the RTM as appropriate (as described in CAISO Tariff Section 34.9). Intertie schedule adjustments (operating adjustments) are only allowed until T-20 minutes, except for System Emergencies and Forced Outages.

➢ The CAISO Real-Time Scheduler manually validates TOR Self-Schedule changes that occur after T-75. After assuring these changes are within the TOR and TTCs, the Real-Time Scheduler records the schedule change as TOR to properly settle the Schedule change.

➢ Once RTM is aware of the changes to the net interchange between Balancing Authority Areas in CAS, the changes are recorded as operational adjustments. To help the Real-Time Scheduler to validate the TOR Self-Schedule changes coming in after T-75, it is expected that the entire TOR Self-Schedule is re-submitted just as it should have been submitted before T-75 (i.e., if an hourly award is 100 MW at Palo Verde and the change at T-30 is an incremental addition of 30 MW, then the revised TOR Self-Schedule is 130 MW). By doing so, the CAISO Operator needs only to check that:

  ➢ The TOR Self-Schedule submitted after T-75 must be not less than the TOR Self-Schedule submitted prior to T-75, if any;

  ➢ The TOR Self-Schedule submitted after T-75 is not greater than the most current transmission right that can be queried from Existing Transmission Contract Calculator (ETCC); and

  ➢ The TOR Self-Schedule changes are within the TTC.

5.1.6   TOR Scheduling Requirements

In the calculation of the Scheduling Point Transmission Interface Limits, the TOR Self-Schedules of the corresponding resources, as submitted by SCs (before being converted to the

regular Self-Schedules even if they are determined invalid by SIBR) are validated by SIBR and scheduled according to the following business rules:

➢ Only physical or System resources can exercise TOR scheduling priorities. The physical and System resources (including aggregations of physical resources) that are pre-specified as sinks or sources for the TOR can be scheduled by different SCs if they are associated with that TOR in the Master File. One physical resource can be a sink or source for multiple TORs.

➢ Several individual TORs can be bid back-to-back, i.e., the sink of one TOR can be the source for another TOR. TOR "chains" are treated as individual TORs, except that their validation is performed on each TOR sequentially (i.e. from the source to the sink using a contiguous path).[21] In such cases where a chain of Transmission Rights are linked a CRN representing the chain of rights will be established.

➢ If a TOR allows a single CNode to be used as both a sink and a source at different times but either a sink or a source at the same time, two CRNs must be created to implement the ownership right.

➢ Multi-point TORs are supported with multiple sources and multiple sinks. Each TOR may be associated with a list of Transmission interfaces, which may include interties. Unused TOR capacity will be reserved only on associated interties. TORs may be used in Wheeling transactions, which are limited from single import to a single export system resource.

➢ Source/Sink Resource IDs identify the resources, including aggregate resources that can be used to submit TOR Self-Schedule. Generating Units and import resources can be listed as sources, and Demand and export resources can be listed as sinks. Pumping Load, including Pumped-Storage Hydro Units, may be listed as sinks when they operate in the pumping mode. Multiple resources may be registered as sources or sinks for the same TOR. A resource may be listed as a source or a sink for many TORs. However, Pumped-Storage Hydro Units may not be listed as a source and a sink simultaneously for the same TOR. The source/sink Resource ID list may not be empty, even for a TOR that does not have a physical right. Resource associations are required even for Inter-SC Trades at Aggregated Pricing Nodes because ISTs involving TORs are associated with physical resources as well as with transmission rights..

---

[21] The chain has to be either ETC or TOR, not a mix of both. However, if the chain is a mix of both ETC and TOR the CRN representing the chain will be assigned the ETC priority.

➤ Source/Sink Resource Maximum TOR capacity (MW). This is the maximum capacity that can be scheduled as a TOR from a resource that is listed as a source or a sink for that TOR.

➤ Source/sink Inter-SC trades at Aggregated Pricing Nodes Location identifiers. These identify the Locations (Price Nodes or Aggregated Pricing Nodes) that are associated with the source/sink resources for the purpose of honoring the applicable transmission right. These ISTs at Aggregated Pricing Nodes Locations may be the physical Locations where the relevant source/sink resources are connected in the Full Network Model (FNM), or different Locations if the Inter-SC trades at Aggregated Pricing Nodes are deployed differently from the physical right.

➤ Inter-SC Trades are not defined as resources that can be used as a source/sink for use of the TOR. However, the physical resource schedules behind a physical inter-SC Trade, not the inter-SC trade itself, can be use as the eligible source/sink for the purpose of validation of the use TOR.

While a number of SCs may use a TOR source/sink pair, a single SC must be designated as the SC for billing purposes for each TOR for Settlement purposes related to such TOR. The TRTC Instructions establishes all the sources and sinks allowed by the TOR.

The validation rules for TORs are described in more detail in Attachment A of BPM for Market Instruments.

5.1.7   ETC and CVR Scheduling Time Requirement

The ETC and CVR scheduling time requirements specifies the time frames in which a SC may submit ETC or CVR Self-Schedules pursuant to their Existing Rights or CVRs and receive scheduling priority afforded to ETC Self-Schedules as further discussed in the CAISO Tariff § 31.4 and 34.10 and according to the relevant provisions of the ETC and the exemption from Congestion Charges as further discussed in CAISO Tariff §§ 11.2.1.5, 11.5.7, 16.5, 16.6. Any specific scheduling time line requirements contained in the ETC must be explicitly included in the TRTC Instructions submitted to CAISO by the relevant PTO. (CAISO Tariff § 16.4)

The following timeline applies to ETC Self-Schedules and CVR Self-Schedules to the extent the scheduling time frame is permissible under the applicable ETC (CAISO Tariff §§ 16.5, 16.6 and 16.9). CVRs receive the same treatment as do Existing rights in the Day-Ahead Market but not in the Real-Time Market (CAISO Tariff § 4.3.1.2):

➤ In DAM, the SC must submit its ETC and CVR Self-Schedule by the close of the DAM (1000 hours) for its Existing Rights. If the SC does not schedule all of its Existing Right

or Converted Rights, then transmission capacity is reserved for the unused ETC amount in the RTM for applicable Scheduling Point(s). Transmission capacity is not reserved for unscheduled amounts of ETC within the CAISO Balancing Authority Area. (CAISO Tariff § 16.5)

➤ In the RTM, the SC must submit ETC Self-Schedules by the close of the RTM (T-75 minutes) if the Existing Right is for capacity on the transmission path at a Scheduling Point. (CAISO Tariff § 16.9.1)

➤ In RTM, CAISO re-dispatches non-ETC or non-TOR resources to accommodate valid ETC Self-Schedule changes in Real-Time provided the TRTC Instruction explicitly allows for such a scheduling right and to the extent such flexibilities do not interfere or jeopardize the safe and reliable operation of the CAISO Controlled Grid or Balancing Authority Area operations. (CAISO Tariff § 16.10)

➤ For ETC Self-Schedule changes between 75 minutes and 20 minutes prior to the Operating Hour, the relevant SC may schedule any remaining Existing Rights by calling the CAISO Operator to input a ETC Self-Schedule change in the RTM as appropriate and permitted under the ETC and further reflected in the TRTC Instructions. Note that transmission capacity for unused Existing Rights is only reserved on transmission paths at Scheduling Points with other Balancing Authority Areas and no internal transmission facilities. Intertie schedule adjustments (operating adjustments) are only allowed until T-20 minutes, except for emergencies and Forced Outages.

➤ The CAISO Real-Time Scheduler manually validates ETC Self-Schedule changes that occur after T-75. After assuring these changes are within the Existing Rights and TTCs, the Real-Time Scheduler records the schedule change as ETC to properly settle the Schedule change. The CAISO accommodates these ETC Self-Schedules through an Exceptional Dispatch. (CAISO Tariff § 34.9.2).

➤ Once RTM is aware of the changes to the net interchange between Balancing Authority Areas in CAS, the changes are recorded as operational adjustments. To help the Real-Time Scheduler validate the ETC Self-Schedule changes coming in after T-75, it is expected that the entire ETC Self-Schedule is re-submitted just as it should have been submitted before T-75 (i.e., if an hourly award is 100 MW at Palo Verde and the change at T-30 is an incremental addition of 30 MW, then the revised ETC Self-Schedule is 130 MW). By doing so, the CAISO Operator needs only to check that:

   ▪ The ETC Self-Schedule submitted after T-75 is not less than the ETC Self-Schedule submitted prior to T-75, if any;

- The ETC Self-Schedule submitted after T-75 is not greater than the most current Existing Right that can be queried from ETCC; and

- The ETC Self-Schedule changes are within the TTC.

5.1.8   ETC and CVR Scheduling Requirements

ETC and CVR Self-Schedules as submitted by SCs are validated by SIBR to ensure consistency with the Existing Rights or CVR as reflected in the TRTC Instructions submitted for the applicable ETC or CVR using the following business rules. Also note that as per section 5.1.2 of market instruments BPM, Converted Rights (CVR) will be submitted into SIBR using the "Self Schedule ETC" Product Type (DAM only) and have the same priority as ETC.

➢ An ETC or CVR may have multiple injection (source) and withdrawal (sink) pairs, which are established by the TRTC Instructions.

➢ Only physical and System Resources (including aggregation of physical resources) can exercise ETC and CVR scheduling priorities. The physical resources that are pre-specified as eligible sinks or sources for the ETC in the TRTC can be scheduled. The physical and System Resources and sink may have different SCs that are responsible for scheduling the resources.   Ultimately, the resources that are identified as eligible to use the ETC shall be stored in the Master-File and will be associated with the applicable Contract Reference Number for validation of the use of the ETC right when scheduling via SIBR. One physical resource can be a sink or source for multiple ETCs, TOR or CVRs. (See CAISO Tariff Section 16.4.5 and Section 17.1.4 for TORs.)

➢ Several individual ETCs or CVRs can be bid back-to-back. ETC or CVR "chains" are treated as individual ETCs or CVRs, except that their validation is performed on each ETC or CVR sequentially (i.e. from the source to the sink using a contiguous path). This is described in more detail in the *BPM for Market Instruments, Section 8*[22]. In such cases where a chain of Transmission Rights are linked a CRN representing the chain of rights will be established.

➢ If an ETC or CVR allows a single PNode to be used as both a sink and a source at different times but either a sink or a source at the same time, two CRNs must be created to implement the Existing Right.

---

[22] The chain has to be either ETC or TOR, or a mix of both. However, if the chain is a mix of both ETC and TOR the CRN representing the chain will be assigned the ETC priority.

➢ Multi-point ETCs are supported with multiple sources and multiple sinks. Each ETC may be associated with a list of Transmission interfaces, which may include interties. Unused ETC capacity will be reserved only on associated interties. ETCs may be used in Wheeling transactions, which are limited from single import to a single export system resource.

➢ Source/Sink Resource IDs identify the resources, including aggregate resources that can be used to submit ETC or CVR Self-Schedule ETCs. Generating Units and System Resources can be listed as sources, and Demand and export resources can be listed as sinks. Pumping Load, including Pumped-Storage Hydro Units, may be listed as sinks when they operate in pumping mode. Multiple resources may be registered as sources or sinks for the same ETC or CVR. A resource may be listed as a source or a sink for many ETCs or CVRs. However, for Pumped-Storage Hydro Units, a single resource may not be listed as a source and a sink simultaneously for the same ETC or CVR. This restriction does not apply to non-pump storage hydro units because such resources are either a source or a sink and not both. The source/sink Resource ID list may not be empty, even for an ETC or CVR that does not have a physical right. Resource associations are required even for Inter-SC Trades at Aggregated Pricing Nodes because ISTs involving ETCs or CVRs are associated with physical resources as well as with transmission rights.

➢ Source/sink resource maximum ETC or CVR capacity (MW). This is the maximum capacity that can be scheduled as an ETC or CVR from a resource that is listed as a source or a sink for that ETC or CVR.

➢ Inter-SC Trades are not defined as resources that can be used as a source/sink for use of the ETC or CVR. However, the physical resource schedules behind a physical inter-SC Trade, not the inter-SC trade itself, can be use as the eligible source/sink for the purpose of validation of the use ETC or CVR.

While a number of SCs may use an ETC or CVR source/sink pair, for every ETC or CVR there is a specific SC designated as the SC for Settlements purposes.

5.1.9 Scheduling Priority for Transmission Rights

In the event that there should be an in ability to clear the CAISO Market because all economic bids have been exhausted, ETC and CVR Self-Schedules are afforded a higher priority than other Self-Schedules. The relative priority level globally for all ETCs and Converted Rights, because they may have different priority levels under the terms and conditions of their contracts, and all TORs which have the same priority level is as follows (CAISO Tariff § 31.4 and 34.10):

> ➤ TORs have the second highest scheduling priority in the CAISO Markets, after RMR Generation Schedules that are needed for reliability. ETC and Converted Rights schedules have the third highest scheduling priority after RMR and TORs.[23] ETCs and CVRs have the same scheduling priority.

SIBR will change the scheduling priority (and treats it like a regular Self-Schedule instead of ETC priority) to the entire ETC Self-Schedules, in the DAM only, if the total ETC Self-Schedules from the sources and the sinks are not balanced

SIBR will reject the ETC or TOR Self-Schedules and will not assign a Price-Taker priority if the ETC or TOR becomes invalid due to any of the following conditions (CAISO Tariff § 16.6):

> ➤ The ETC or TOR Self-Schedule is submitted with an incorrect Contract Reference Number

> ➤ The ETC or TOR Self-Schedule exceeds the resource capacity limit of the relevant ETC or TOR based on the TRTC Instructions

> ➤ The available capacity MWh limit in total exceed the non-zero available capacity MW limit permissible under relevant ETC or TOR.

5.1.10   ETC, CVR & TOR Settlement

The following summarizes the Settlement associated with ETCs and TORs:

> ➤ Both ETC and TOR Self-Schedules are not assessed the Access Charges and Congestion Charges for the balanced and valid portion of their ETC and TOR Self-Schedules. (CAISO Tariff § 16.6.3 and 17.3.3). CVRs are also not assessed Congestion Charges from the Day Ahead. (CAISO Tariff § 4.3.1.2) The Settlement mechanism reverses Congestion Charges in the same way for both TOR, CVR and ETC Self-Schedules.

> ➤ Unlike ETC Self-Schedules, TOR Self-Schedules also are exempt from UFE, Imbalance Energy offset, and neutrality charges. (CAISO Tariff § 17.3.3(3))

---

[23] Section 6.6.5.3, Scheduling Priorities, Section 7.5.3.2, RTM Self-Schedules and Section 7.5.3.3, Self-Schedules in HASP provide additional information on scheduling priorities.

➢ ETC and CVR Self-Schedules are settled at Custom LAP (specific nodal) prices. Both are subject to Marginal Losses and the SCs submitting these ETC, CVR or TOR Self-Schedules receive refunds for the over collection of IFM Marginal Losses, based on system wide Marginal Loss revenue over-collection based on their Measured Demand. (CAISO Tariff § 11.2.1.6).

➢ ETC Self-Schedules are validated against the TRTC Instructions submitted by the PTO.

➢ TOR Self-Schedules are validated based on the TRTC Instructions developed by the Non-Participating TO with the CAISO.

➢ CVRs Self-Schedules in the Day Ahead are validated based on the TRTC Instructions submitted by the CVR holder and as appropriate with any applicable original PTO and were appropriate as provided in the CAISO Tariff § 4.3.1.2.1.

Additional details are provided in the Section 11 of the CAISO Tariff and *in the BPM for Settlements and Billing, Section 8*.

5.1.11   Transmission Rights & Curtailment Instructions (TRTC)

This section is based on CAISO Tariff § 16.4. Holders of Converted Rights, that are not associated with an Existing Contract must also submit TRTC Instructions for the Converted Rights as provided in CAISO Tariff § 4.3.1.2.1. In addition, holders of Transmission Ownership Rights (Non-Participating Transmission Owners) must also submit TRTC Instructions for their TORs (CAISO Tariff § 17.1.3)

Each PTO must work with the Existing Rights holders, to develop the TRTC Instructions. Holders of TORs must complete the TRTC Instructions for their applicable rights. New Participating TOs must complete the TRTC Instructions for the Converted Rights that they hold, that are not associated with an Existing Contract. In the event that Converted Rights are derived from ETCs that were converted involving an Original Participating Transmission Owner, the New Participating TO must develop the TRTC Instructions with the Original PTO. The TRTC Instructions must allow ETCs, Converted Rights and TORs to be exercised in a way that:

➢ Maintains the existing scheduling and curtailment priorities established in the ETC, Converted Rights, or if applicable TOR contract

➢ Is not unreasonably burdensome to CAISO (i.e., does not create an unreasonable impact on CAISO's preferred operational policies and procedures)

➢ Is consistent with the terms of the ETCs, Converted Rights or TORs and including preserving the operational characteristics of the ETCs or Converted Rights, while making as much transmission capacity not otherwise utilized by the holder of Existing Rights or Converted Rights as possible available to CAISO for allocation to Market Participants

➢ Is not unreasonably burdensome to the PTO, Non-Participating TO or New Participating TO and the Existing Rights holder from an operational point of view

➢ The TRTC Instructions should be provided in a clear enough fashion that does not require CAISO to engage in interpretation of the ETCs or Converted Rights to make assumptions about the economics of the deals struck in the contracts. These TRTC Instructions must be implementable without further interpretation by the CAISO.

The parties to ETCs attempt to jointly develop and agree on any TRTC Instructions that are submitted to CAISO. The parties to an ETC are also responsible to submit to CAISO any other necessary operating instructions based on their contract interpretations needed by CAISO to enable CAISO to perform its duties. If the holder of Existing Rights and the PTO disagree on the TRTC or operating instructions, CAISO implements TRTC or the operating instructions provided by the PTO in accordance with the CAISO Tariff.

In the calculation of Transmission Interface Limits, ETC reservations (i.e. the differences between ETC Encumbrances and ETC Self-Schedules) are considered only on Intertie Transmission Interfaces. The determination of the Limits for internal Transmission Interfaces used by the market software disregards ETC Encumbrances.

Transmission reservations at the interties for ETCs and CVRs are held in accordance with the Existing Rights or CVRs. The quantity of capacity consistent with the TRTC instructions is reserved for ETCs at the Interties. ETC capacity entitlements that are not associated with an Intertie are not reserved but are managed if necessary using redispatch. For CVR, unused CVR rights are available for use by others in the Day-Ahead Market, therefore the CVR rights are not reserved. The PTOs provide TRTC Instructions to CAISO to decide which Scheduling Point ETC has reservation requirements in which markets. Such instructions are part of the look-up tables or formulas for calculating the ETC Encumbrances. No ETC reservation is made in the DAM and RTM unless explicit instructions for reservation by markets are provided to CAISO.

The TRTC Instructions identify the relevant Transmission Interfaces, also known as Transmission Interfaces, for ATC calculations and transmission capacity reservations. ATC calculation is performed for OASIS for each intertie and commercially significant paths, using

the relevant TTC and ETC Encumbrances calculated by ETCC. Transmission capacity is reserved for unused Encumbrances by the market applications only on intertie Transmission Interfaces. If the Transmission Interface identifier is not unique and directional, a direction must also be specified.

Additional guidelines for completion and submission of the TRTC Instructions are posted on the CAISO website.

5.1.12 ETCs, CVRs and TORs Treatment in the Release of CRRs

The CAISO creates but does not release CRRs associated with expected use of ETCs and CVRs. CAISO models holders of Existing Right use of the CAISO Controlled Grid so the non-collection of the Congestion Charges does not create revenue inadequacy in the CRR allocation process.   In its preparation of the Full Network Model for CRRs, the CAISO makes an adjustment to the available capacity for the TOR capacity identified through the TRTC Instructions. This is described in more detail in the BPM *for CRRs* and in Section 36.4 of the CAISO Tariff.

5.2 Available Transfer Capability Calculation

The purpose of calculating Available Transfer Capability (ATC) is for publication on OASIS. The following formulas are used to calculate ATC for all Transmission Interfaces including Scheduling Point Transmission Interfaces and internal Transmission Interfaces such as Path 15 and Path 26.

5.2.1 ATC Calculation before DAM Closes

Before DAM closes (i.e., before 1000 hours one day ahead) for the Trading Day, there are no ETC/TOR Schedule, net Energy Schedule, or AS Schedule on the Transmission Interface for the Trading Day. Therefore, the ATC for a Transmission Interface is calculated as follows.

> Before DAM: ATC = Hourly TTC – CBM – Total Transmission Interface ETC Capacity – Total Transmission Interface TOR Capacity – TRM

Where:

> Hourly TTC = Seasonal TTC – Constraint/derate caused by outages

> Total Transmission Interface ETC/TOR Capacity = the sum of all the Capacity on the Transmission Interface.

Total Transmission Interface TOR = the sum of all the TORs on the Transmission Interface.

The ATC needs to be updated whenever TTC changes. TRM and CBM are at all times set at zero in the Day-Ahead Market.

5.2.2   ATC Calculation After DAM Completes & Before RTM Closes

After DAM completes and before RTM closes (i.e., after 1300 hours the day-ahead and before T-75 minutes of the Trading Hour), the ATC on each Transmission Interface for the Trading Hour is calculated as follows:

After DAM, for non-Intertie Transmission interfaces: ATC = Hourly TTC – CBM – TRM – Total Transmission Interface ETC Capacity – Total Transmission Interface TOR Capacity – DA net Energy Scheduled Flow

After DAM, for Interties: Import ATC = Import Hourly TTC – CBM – TRM – Total Import ETC Capacity – Total Import TOR Capacity – DA net Energy Scheduled Import – Total DA Regulation Up/ Spin/Non-Spin Import Awards

After DAM, for Interties: Export ATC = Export Hourly TTC – CBM – TRM – Total Export ETC Capacity – Total Export TOR Capacity – DA net Energy Scheduled Export – Total DA Regulation Down Import Awards

Where:

DA net Energy Scheduled Flow is the net DA scheduled Energy flow on the Transmission Interface in the relevant direction.

For each Transmission Interface in a specific direction, the Total Transmission Interface ETC Capacity is the sum of the expected DA ETC Schedule for the entire ETC on the Transmission Interface in the direction. For each Transmission Interface in a specific direction, the expected Total DA TOR Schedule is the sum of the expected DA TOR Schedule for all the TORs on the Transmission Interface in the direction. In the calculations set forth above, CBM is at all times set at zero. For non-Intertie Transmission interfaces, TRM is also at all times set at zero. For Interties, TRM values are established in accordance with the procedures identified in section L.1.6 of Appendix L to the Tariff the ISO's NERC-mandated TRM Implementation Document.

5.2.3   ATC Calculation After RTM Completes

After RTM completes (after the Trading Hour), the Total ETC and TOR Reservation is zero, and the ATC calculation becomes the following:

After RTM: ATC =   Hourly TTC – CBM – TRM – RT net Energy Scheduled Flow

Where:

RT net Energy Scheduled Flow is the total Real-Time Scheduled average energy flow on the Transmission Interface in the relevant direction during the Trading Hour.

6.   Day-Ahead Market Processes

Welcome to the *Day-Ahead Market Processes* section of the CAISO *BPM for Market Operations.* In this section, you will find the following information:

> ➢ How CAISO determines and applies Market Power Mitigation
> ➢ How CAISO clears the Integrated Forward Market
> ➢ How CAISO performs the Residual Unit Commitment process

A timeline and data flow diagram is included for the Day-Ahead Market Processes, as shown in Exhibit 6-1, Day-Ahead Market Timeline.

6.1   Pre-Market Activities

There are many activities that take place in preparation for the DAM, as shown by the overview timeline in Exhibit 2-1 and as described in this section.

6.1.1   Congestion Revenue Rights

Congestion Revenue Rights (CRRs) have no direct effect on the scheduling of Power in the CAISO Markets. However, the holders of CRRs are charged or credited for Congestion in DAM as described in the *BPM for Settlements & Billing*.

6.1.2   Full Network Model Build

One of the continuing CAISO processes is that of building and updating the FNM for power system operations and for the CAISO Markets. This process is described in more detail in the *BPM for Managing Full Network Model*.

6.1.3   Bid Information

Seven days before the Trading Day, the DAM is opened and ready to accept Virtual and physical Bid information from the SCs.

See the *BPM for Market Instruments* for more information.

6.1.4   Outage Information

Outage information may be submitted up to 12 months in advance of the Trading Day.

Three days before the Trading Day, the DAM (via the outage management system application) is ready to process Outage information for the DAM applications:

➤ Planned transmission Outage requests received 45 days in advance
➤ Review for possible adverse impacts on the CAISO Controlled Grid and CAISO Balancing Authority Area
➤ Planned Generating Unit Outage requests received 72 hours in advance for all types of units
➤ Review for possible adverse impacts on the CAISO Balancing Authority Area
➤ Approve or deny the requests.
➤ Outages over-ride Bids. If outage results in a more restrictive range in supplying Energy and providing Ancillary Services, the more restrictive range is used in market applications in performing Scheduling.
➤ Create the Outage schedule to be used by the market applications

For resources, outage information may be submitted for the following limitations:

➤ Resource is offline
➤ Resource is unable to provide Regulation
➤ Resource has more restrictive minimum and maximum operating limits than is recorded in the Master File.
➤ Resource has a different ramp rate than what was bid in.

6.1.5   CAISO Demand Forecast Information

Two days before the Trading Day, the DAM produces a CAISO Forecast of CAISO Demand via the Automated Demand Forecasting System (ALFS) application and publishes the forecast based on:

➤ Weather data
➤ Actual Load
➤ Historical information

CAISO produces a CAISO Forecast of CAISO Demand (CFCD) for each Trading Hour of the next three Trading Days to support the DAM, and a Load projection for each 15-min and five-min interval within the Time Horizon of the RTM applications. The CFCD is updated every half hour and is based on a regression of historical data and up-to-date weather forecast in terms of temperature information. The Demand projection is based on the CFCD and extrapolates actual Demand from the State Estimator solution using a neural network methodology. The CFCD is published on OASIS for each Demand Zone several days in advance and is updated regularly during Real-Time.

6.1.6 Determine Total Transfer Capability

Two days before the Trading Day the CAISO determines the TTCs of the transmission interfaces and publishes that information by 1800 hours at the OASIS.

6.1.7 Before Day-Ahead Market is Closed

The following activities are performed one day before the Trading Day before the DAM closes:

➢ By 0530 hours, the CAISO compiles Eligible Intermittent Resource (EIR) data based on a seven-day true wind forecast.
➢ By 0830 hours, the CAISO updates and publishes the available ETC capacities.
➢ By 0830 hours, the CAISO determines and publishes the ATCs.

Since a lot of transactions outside of CAISO Balancing Authority Area take place by 0500 hours, if there are changes to TTC after 0500 hours, CAISO needs to coordinate with other Balancing Authority Areas and communicates updates if they occur.

Generally, CAISO can make changes that result in an impact to the CAISO markets due to a change in outage conditions up to 0800 hours in coordination with other Balancing Authority Areas (BAA), and provide information back to Market Participants. If there is a change in TTC by that time that results in a reduction in ETC rights, any ETC Self-Schedules that have been submitted are revalidated at that time and the SC scheduling such ETC is informed of any violations. If there is an increase in TTC, the changes will only increase the feasibility of submitted schedules. In either case, CAISO makes updates to Market Participants, if needed. If the changes to the market systems due to a change in an outage in the CAISO Controlled Grid are submitted after 0800 hours, they will only be entered into market systems on an exception basis and only if all of the following can be completed before 0900 hours:

▪ they can be fully coordinated with other affected Transmission Operators and BAAs, and
▪ entered into all systems affected by the change.

CAISO publishes based on known network conditions, e.g., knows that a line is down, and incorporates that information. Also, temperature forecasts, which lead to derating a line, are also included when data is published. Details of reports provided by CAISO are shown in *BPM for Market Instruments*, Section 13.

TTC/ATC continues to be published seven days in advance. The following is published on OASIS:

- ➢ Transmission Interface capacities
- ➢ Load forecast
- ➢ Expected flow
- ➢ Scheduled derates

6.1.8   Overgeneration Condition

Overgeneration is a condition that occurs when there is more physical Supply that is scheduled and generating than there is physical Demand to consume the Energy.

In IFM, Overgeneration is managed as part of the IFM Unit Commitment process. However, IFM cannot de-commit self-scheduled resources. Overgeneration condition in IFM may manifest when self-scheduled supply exceeds total bid-in demand. In this case, overgeneration will be resolved by reducing self-scheduled generation through the adjustment of non-priced quantities pursuant to the scheduling priorities specified in Section 31.4.

It is possible that the scheduled Demand in DAM has been over-scheduled relative to the forecast or actual Demand. Additionally, circumstances may occur where large amounts of Virtual Demand Awards cause an excess of physical Supply to be scheduled in IFM relative to the CAISO Forecast of CAISO Demand. If the scheduled CAISO Demand exceeds the CAISO Forecast of CAISO Demand when performing RUC, RUC may reduce supply scheduled in IFM down to minimum load through uneconomic adjustments but RUC does not automatically de-commit a resource scheduled in IFM. The CAISO Operator may communicate the need for de-commitment of resources with affected Market Participants.

It is also possible that an excessive amount of Virtual Supply versus Virtual Demand is cleared in IFM, such that there is "virtual" overgeneration. Since RUC only runs with physical Bids and CAISO Forecast of CAISO Demand, and to the extent that Virtual Supply has displaced physical Supply, RUC may need to commit more physical resources and/or more RUC capacity maybe awarded in order to make sure that there is enough physical capacity covering the CAISO Forecast of CAISO Demand.

If the scheduled CAISO Demand exceeds the CAISO Forecast of CAISO Demand when performing FMM, the CAISO uses the opportunity to deal with Overgeneration by economically clearing an Export Bid in FMM, in order to avoid manual intervention to decrease generation in Real Time.

If the Overgeneration condition continues in Real-Time, RTM attempts to dispatch resources down using economic Bids to the extent possible to relieve the Overgeneration condition. If use of economic Bids is insufficient, then supply curtailment is performed through uneconomic adjustments in the order established in accordance with Section 34.10.2 of the CAISO Tariff. Additionally, RTUC may optimally de-commit resources in real time (refer to section 7). Lastly, Exceptional Dispatches may be necessary to resolve the Overgeneration condition including situations created by "virtual" overgeneration in the IFM due to Virtual Bidding. Exceptional Dispatches may also include manual resource de-commitment.

Detailed information can be found in Operating Procedure G202, Overgeneration.

6.1.9   IFM Initial Conditions

A Generating Unit that was committed in the previous day's Day-Ahead Market (IFM or RUC) run (TD-2 for TD-1) but was de-committed before HE24 would normally be considered initially offline in the next day's IFM run for the Trading Day (TD). However, in the event that the Scheduling Coordinator for such Generating Units have submitted Self-Schedules in the Real-Time Market for the remaining hours of the day in which it was not committed in the Day-Ahead Market for the TD-1 date, the CAISO may assume that the Generating Unit is indicating its intent to be on line at the beginning of the next day (TD). In that case, the CAISO market operator may set the initial condition for such a resource in the IFM conducted on TD-1 for the TD to be online taking into consideration the following conditions:

- The unit was offered in the Day-Ahead Market for all hours through hour ending 24 where it was not economically committed by the IFM from the previous day (TD-1)
- The unit is economically committed for some hours of the TD-2 for TD-1 IFM or RUC processes, but is not committed through the end of TD-1. An IFM partial day self-schedule commitment will not trigger this criterion.
- By one hour prior to the close of the Day-Ahead Market for TD (i.e. at 09:00 on TD-1), the unit has Self-Scheduled Energy (presumably, but not necessarily at PMin) in the RTM for TD-1 for each of the remaining hours after the last economically-committed hour in the DAM for TD-1.
- No risk of an over-generation condition is anticipated for any hours in TD-1.

In addition, the CAISO monitors the interaction of the initial condition setting and Self-Schedule behavior by Scheduling Coordinators. For example, If the CAISO observes that a Scheduling Coordinator tends to withdraw its Self-Schedules after the close of the Day-Ahead Market, but prior to the close of Real-Time Market, the CAISO can consider such behavior and inform its decisions in setting the initial conditions for the next day's IFM.

The initial condition of the resource consists of the resource's status, operating level, and for Multi-Stage Generating Resources, the operating MSG Configuration. When the operator, following this process, adjusts a resource's initial condition, they will adjust the operating level and MSG Configuration as follows:

- Non- Multi-Stage Generating Resource – the operating level will be set to the resource's Minimum Load
- Multi-Stage Generating Resource – the MSG Configuration will be set to the lower of a) the configuration in the last hour of the IFM commitment for TD-1; and b) the self-scheduled configuration in the Real-Time Bid for Hour Ending 24 on TD-1. The operating level will be set to the Minimum Load of the selected MSG Configuration.

The initial condition will be set to the Minimum Load of the unit / MSG Configuration even if the RTM Self-Schedule is higher than Minimum Load. If the SC only offered the unit to be self-scheduled in the IFM run on TD-2 for TD-1, then the unit will not be a candidate for its initial condition to be set as online for the IFM run for the TD run on TD-1. The CAISO monitors how the Generating Units Self-Schedule their resources to inform the decisions the operators make in setting the initial conditions based on their self-scheduling practices.

On any given day that the CAISO does not consider the next day's Self-Schedules in setting initial conditions, the CAISO will notify Scheduling Coordinators via the OASIS system operating messages. Furthermore, the setting of a resource's initial conditions does not supersede the scheduling of resources in IFM through the security constrained economic dispatch and unit commitment process of the IFM for a given Trading Day and only serves as an input to the IFM to inform operators on setting the resource's initial conditions to facilitate a more efficient operation of the market and grid.

In setting the initial conditions in the Day-Ahead Market for TD the ISO operator or systems may also consider a resource's actual status (on-line or off-line) and on time (how long the resource has been in its current status) at the time of the close of the market (1000 TD-1). If a resource that does not have a Day-Ahead Market schedule for the previous and current hours of the current day in which the Day-Ahead Market is run is actually online at the time of the close of the Day-Ahead Market for TD (1000 TD-1), and in addition has a Day-Ahead Market schedule for a future hour of the current day including hour ending 24 of the current day, then an assessment of the resources ability to actually cycle off and back on prior to its upcoming schedule of the day may occur. If the ISO operator or systems determine that the resource would be unable to cycle off and back on without violating the resources registered minimum down time, then the resources on time will reflect its actual time on, as of the close of the market, plus the remaining hours of the current day.

6.2   Day-Ahead Market Timeline

The detailed Day-Ahead Market timeline is shown by Exhibit 6-1, showing the execution of the principal application functions, i.e., MPM, IFM, and RUC. Each of these applications is described in detail in later sections of this BPM.

Exhibit 6-1: Day-Ahead Market Timeline
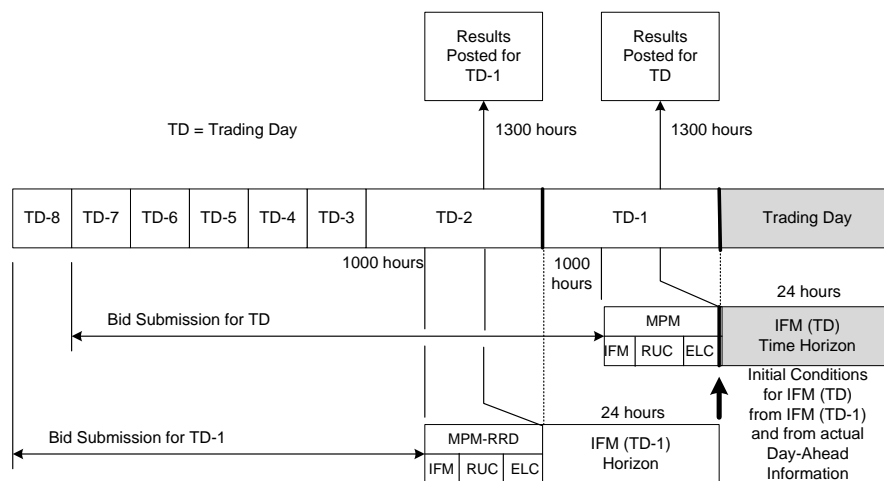
6.3   Scheduling Coordinator Activities

The SCs are the entities that interact directly with the CAISO Markets. They are responsible for submitting Bids into the CAISO Markets and to respond to the Dispatch Instructions and Unit Commitment Instructions of CAISO, resulting from the CAISO Markets.

6.3.1   Submit Bids

SCs submit Bids (for Supply, Virtual Supply, Demand, and Virtual Demand) for each resource to be used in DAM. DAM includes the MPM, the IFM and RUC. SCs may submit Bids for DAM as early as seven days ahead of the targeted Trading Day and up to Market Close of DAM for the target Trading Day. CAISO validates all Bids submitted to DAM, pursuant to the procedures set forth in Section 30.7 of the CAISO Tariff.   In the case of Virtual Bids (Supply and Demand), credit checks are performed against the Parent SC's (which provides financial collateral for itself and subordinate SCs) available credit limit prior to passing the Virtual Bids to the Day-Ahead Market.

SCs must submit Bids for RA Capacity into the IFM and the RUC process as required in Section 40 of the CAISO Tariff.   SC's obligations to submit bids for RA Capacity are described in detail in the BPM for Reliability Requirements.

To the extent that the SC wants to participate in any of the following markets, the following information must be submitted by the SCs before Market Close in order to participate in DAM:

➢ Energy Bids (Supply and Demand)

> ➢ Ancillary Services Bids
> ➢ RUC Availability Bids
> ➢ Self-Schedules
> ➢ Ancillary Services self-provision
> ➢ Virtual Energy Bids (Virtual Supply, and Virtual Demand)

Further details are given in the *BPM for Market Instruments*, Sections 5, 6 and 7

6.3.2   Interchange Transactions & ~~e-Tag~~E-Tagging

Consistent with NERC standards, SCs should submit ~~e-Tag~~E-Tags for DAM Schedules, which are due in DAM scheduling timeline, consistent with the WECC business practice and NERC standards.

The following types of DAM interchange transactions at Scheduling Points must be ~~e-Tag~~E-Tagged:

> ➢ Ancillary Services Bids – For the capacity ~~e-Tag~~E-Tag, the Energy profile equals zero. However, the transmission allocation profile is equal to the awarded Bid. If the Ancillary Services capacity is converted to Energy, the tag's Energy profile is adjusted to the dispatched quantity.
>
> ➢ Supply and Demand Bids and Self-Schedules
>
> ➢ TOR, ETC and CVR Self-Schedules
>
> ➢ RUC capacity is not tagged. Energy associated with a RUC Schedule dispatched on at an Intertie is to be tagged as Energy and not capacity consistent with the NERC standards.

To enable CAISO to match and validate the ~~e-Tag~~E-Tags with the corresponding market reservations, the following market information must be included on each ~~e-Tag~~E-Tag in the Misc. Information field of the Physical Path:

> ➢ Energy Type: ENGY,SPIN or NSPN
> ➢ Transmission Right Identifier, i.e., Contract Reference Number (CRN), applicable to ETC/TOR/CVR self-schedules.
> ➢ Resource ID/ Transaction ID

If an ~~e-Tag~~E-Tag is submitted before DAM is final and is correct, the ~~e-Tag~~E-Tag is approved with a disclaimer. If DAM clears at a lower MW value than the tag's transmission allocation, then the ~~e-Tag~~E-Tag is adjusted down to match the Day-Ahead Schedule or AS Award.

6.3.3   Respond to Day-Ahead Market Published Schedules & Awards

It is the responsibility of SCs to respond to CAISO published Schedules and Awards starting up units and achieving specified operating levels in a timely manner. SCs are also financially responsible for awarded Bids and Self-Schedules into the CAISO Markets.

Consistent with the RMR Contract, Generating Units are required to start when instructed by CAISO, even if the market is late.

6.4   CAISO Activities

CAISO performs the following activities, described in the following sections, in the context of the DAM:

6.4.1   Accept Day-Ahead Market Inputs

CAISO accepts DAM inputs from the following principal sources:

➢ SIBR
➢ Master File
➢ ETCC
➢ outage management system/ALFS

6.4.2   Disseminate Pre-Market Information

The following information is published in support of the DAM:

➢ Public Transmission information in OASIS:
  ▪ Future planned Outages of transmission facilities
  ▪ Operational Transfer Capability and Available Transfer Capability on Transmission Interfaces including   WECC paths and interconnections with external Balancing Authority Areas.

➢ Demand forecast public information in OASIS:
  ▪ Beginning seven days prior to the Trading Day, and updated as necessary, CAISO publishes its peak CAISO Demand forecasts by IOU service territory.
  ▪ By 1800 hours the day prior to (two days before the Operating Day) the target DAM, CAISO publishes its updated CAISO Demand forecast by IOU service territory.

➢ Network and system conditions public information in OASIS[24]:

- By 1800 hours two days ahead of the Trading Day, CAISO publishes known network and system conditions, including but not limited to TTC and ATC, the total capacity of Inter-Balancing Authority Area Interfaces, and the available capacity.

➢ Ancillary Services requirements public information in OASIS:

- By 1800 hours two days ahead of the Trading Day, CAISO publishes forecasted AS requirements and regional constraints by AS Region. A minimum and/or maximum constraint, expressed as hourly MW, is given for each AS Region. For AS Regions where no limit is applicable, the CAISO publishes a 0 MW minimum and/or an appropriately large maximum.

➢ Relevant Gas Price Indexes public information in OASIS when available. Refer to the *BPM for Market Instruments, Attachment C* for details.

➢ SIBR sends messages to SCs regarding the status of their Bid validation continuously as Bids are submitted until the DAM is closed at 1000 hours.

➢ SIBR sends messages to SCs regarding the status of their trade validation continuously as trades are submitted and for physical trade pre-market validation, every 20 minutes between 6:00 am and the close of the trade market 11:00 am.

6.4.3   Disseminate Post Market Close Information

The following information is published in support of the DAM following Market Close:

➢ After the close of the DAM bidding at 1000 hours, CAISO sends a message to the SCs regarding the final outcome of the Bid validation.

➢ By 1300 hours, CAISO publishes the result of the DAM and the resource is flagged if it is being Dispatched under its RMR Contract. Any such Dispatch is deemed a Dispatch Notice under the RMR Contract.

6.4.4   Procedures for Closing the Day-Ahead Market

Bidding for DAM is closed at 1000 hours on the day preceding the Trading Day.

---

[24] CAISO understands the MPs' desire for market related information. How ever, there may be limitations on the publication of data for non-competitive constraints due to market sensitivity, pow er system security and the confidentiality of data provided to CAISO by MPs.

Consistent with Sections 7.6 and 7.7 of the CAISO tariff, the following actions are taken in the event of market disruptions. Actions taken vary depending on the cause of failure, expected time of resolution, and the status of the submitted Bids at the point of failure:

➢ Postpone the closure of the market. Postponement may be accommodated for a maximum of approximately two hours without impacting scheduling and Balancing Authority Area check out processes.

➢ Closing of the market and manual copying of Bids or Schedules from previous Trading Day.

➢ Closing of the market and using submitted Bids to the extent possible. Note, CAISO recommends that Scheduling Coordinators have seven days of Bids submitted to SIBR as a default in case Bids are not able to be submitted for a particular Trading Day.

➢ Cancellation of the market with import/export schedules being determined by submittal of an ~~e-Tag~~E-Tag. Established WECC scheduling rules apply when a failure of an ~~e-Tag~~E-Tag occurs when submitting interchange transactions~~.~~

➢ Suspension of all Virtual Bids at specific Eligible Pnodes or all Eligible Pnodes to allow all physical Bids to be cleared.

➢ If cancellation of the market or suspension of all Virtual Bids occurs, CAISO may issue operating orders for resources to be committed and dispatched to meet Demand. In this case, CAISO will set administrative prices to be used for settling Metered Supply and Demand as reflected in Section 7.7 of the CAISO Tariff.

Validation for Bids at Transmission Paths with Zero Rated TTC in Both Directions

As further discussed in the BPM for Market Instruments, the ISO market systems will validate all Bids, including Self-Schedules and Virtual Bids, for each Trading Hour to ensure that Bids submitted at open ties (i.e., interties where the transmission path TTC is rated to zero in both directions) are not considered in the ISO market processes, as required by Section 30.8 of the ISO Tariff.   However, bids for System Resources which have registered an alternate tie path in the Master File will be considered in the IFM to be bid at the alternate path if the primary tie path is open. For these resources, if both the primary and alternate path is open, only then will the bid not be considered in the ISO market processes.

No Bids at Transmission Paths with Zero Available Transmission Capacity (ATC)

With the exception of transmission rights holders, the ISO will not accept Bids, including Self-Schedules and Virtual Bids, at an intertie Scheduling Point that is fully encumbered by transmission rights holders where the ATC is set to 0 MW.

6.4.5 Execute Day-Ahead Market Applications

The following Day-Ahead applications are executed by CAISO after the Market Closes:

➢ MPM
➢ IFM
➢ RUC

6.4.6 Publish Reports to Scheduling Coordinators

The following is a summary of the Day-Ahead reports available to SCs for online viewing after the DAM has completed its execution[25]:

➢ **Day-Ahead Generation Market Results** – Schedules of all generating resources.

➢ **Day-Ahead Load Market Results** – Schedules of both Participating Loads and Non-Participating Loads from the DAM.

➢ **Convergence Bid Clearing Results** – Virtual Supply Awards and Virtual Demand Awards from the IFM.

➢ **Day-Ahead RUC Capacity** – Incremental capacity amount committed or scheduled in the RUC, above the Day-Ahead Schedule.

➢ **Day-Ahead Import/Export Schedules** – Import and export Schedules from the DAM.

➢ **Day-Ahead Start-Up & Shutdown Instruction**s – Commitment instructions of all resources from the DAM.

➢ **Day-Ahead Ancillary Services Awards from accepted Bids and qualified Self-Provision** – Awards for AS MW quantity, by AS type and resource from the DAM.

➢ **Day-Ahead MPM Results** – Information about the "Mitigated" Bid that is used if the original Bid is modified in the MPM process. In addition the following MPM results will be published for informational purposes: LMPs at all PNodes and Apnodes with market resources associated with physical bids; shadow prices for all binding constraints;

---

[25] Note: the SC's confidential information is available only to the SC.

competitive path determination for all binding constraints; and reference bus identification.

➢ **Non-Participant Price Curves** – Information on the Default Energy Bids supplied by an independent entity used in MPM. Day-Ahead Inter-SC Trades – Inter-SC Trade schedules for both Inter-SC Trades at Aggregate Pricing Nodes and Physical Trades , for both Inter-SC Trades of IFM Load Uplift Obligation and Ancillary Services from the DAM

➢ **Day-Ahead Resource Energy Prices –** Resource-specific (LMPs and ASMPs).

➢ **Day-Ahead Resource Ancillary Service Prices –** Resource- specific ASMPs.

➢ **Self-Provided AS Awards**.

➢ **Day-Ahead Unit Commitments** - Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market

➢ **Default RMR Minimum Load & Startup Cost Bid Curves** - Independent entity-supplied default Minimum Load and Start-Up cost bid curves used in the Market Power Mitigation process. This applies to RMR units only.

➢ **Day-Ahead LMPs at all Pnodes for informational purposes.**

➢ **Extremely Long-Start Resource Startup Instructions** - Startup instructions resulting from the Extremely Long-Start Commitment (ELC) process.

➢ **Day-Ahead Reliability Must Run (RMR) Dispatches** – RMR units that either have an energy schedule (from the IFM run) and / or an RMR dispatch

➢ **Conformed Dispatch Notice (CDN)** - Summary of the Day-Ahead Energy Schedules, Ancillary Service Awards, RMR Dispatches, Competitive Constraint Run results of RMR resources. This is available on CMRI.

➢ **Shadow prices for the interties –** Shadow prices for the interties are available in OASIS.

➢ **Volume of Virtual Awards** - System wide total Virtual Supply Awards and Virtual Demand Awards

➢ **Maximum MW limit per Eligible PNode and Eligible APNode** – Maximum nodal MW limit used to apply the Position Limits to Virtual Bid

➢ **Hourly Prices due to Convergence Bidding for CRR Adjustment Report –** Hourly LMP differentials between Day-Ahead Market and Real-Time Market used for CRR revenue adjustments caused by Virtual Bids under the CRR Settlement Rule.

➢ **Binding Transmission Constraints due to Convergence Bidding for CRR Adjustment Report –** Provides listing and status of PNodes associated with transmission constraints and whether their binding constraints were due to Virtual or physical Bidding activity in IFM. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

➢ **Flow Impact Due to Convergence Bidding for CRR Adjustment Report -** Reports hourly MW flow contributions for transmission constraints impacted by SCs submitting Virtual Bids on behalf of a Convergence Bidding Entity that is also a CRR Holder. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

Refer to the *BPM for Market Instruments, Sections 10 and 12* for the detailed contents of these records.

6.4.7   Resource Commitment

The commitment of resources by the Day-Ahead and Real-Time applications is shown in Exhibit 6-2.

Exhibit 6-2: Generating Unit Commitment Selection by Application

Attribute	Fast Start	Short-Start	Medium Start	Long-Start	Extremely Long-Start
Start Up Time	less than or equal to 10 minutes	less than 2 hours	between 2 & 5 hours	between 5 & 18 hours	greater than 18 hours
Cycle Time		less than or equal to 270 mins	less than or equal to 270 mins		
Day-Ahead Applications					
IFM	Commit	Commit	Commit	Commit	No Commit
RUC	Advisory	Advisory	Advisory	Commit	Advisory Commit
ELC[26]	Advisory	Advisory	Advisory	Advisory	Commit

---

[26] Extremely Long-Start Commitment Process

Attribute	Fast Start	Short-Start	Medium Start	Long-Start	Extremely Long-Start
Real-Time Applications					
RTUC	Commit/ Advisory	Commit/ Advisory	No Commit	No Commit	No Commit
STUC	Commit/ Advisory	Commit/ Advisory	Commit	No Commit	No Commit

6.5   Market Power Mitigation

The market power mitigation process is to identify under which scheduling coordinators can exercise local market power in circumstances where there are insufficient resources to rely on competition to mitigate constraints based on market bids. In the absence of sufficient resources to rely on competition, scheduling coordinators could potentially manipulate the energy price in its local area by economically withholding supply. Any scheduling coordinators that are identified through this process will be subject to bid mitigation.

The MPM process will consist of a single market optimization run in which all modeled transmission constraints are enforced. It will utilize the same market optimization engine as used in the CAISO's IFM and RUC. Some characteristics of DAM LMPM are summarized as follows:

➢ The MPM process occurs in DAM immediately after the DAM close of bidding at 1000 hours, by when all Bids and Self-Schedules are submitted by the SCs and validated by CAISO.

➢ The Time Horizon for MPM in DAM is 24 hours (23 and 25 respectively on Daylight Saving transition days).

➢ Each market interval for MPM in DAM is one hour

  ➢ The time resolution of the CAISO Forecast of CAISO Demand in DAM is hourly.

  ➢ The Energy Bid mitigation in DAM is performed on an hourly basis.

➢ Bids on behalf of Demand Response Resources, Non-Generator Resources and Virtual Bids are considered in the MPM process as part of the power balance equation; however these bids are not subject to mitigation.

> Multi-Stage Generating Resources will be subject to the market power mitigation procedures described in Section 31.2 of the CAISO Tariff at the MSG Configuration basis as opposed to the overall plant level.

6.5.1   Decomposition method

The MPM method is referred as the locational marginal price decomposition method (or LMP decomposition method). It consists of a single market optimization run in which all modeled transmission constraints are enforced. Then, each LMP in the market will be decomposed into four components: (1) the energy component; (2) the loss component; (3) the competitive congestion component; and (4) the non-competitive congestion component. For location i:

$$LMP_i = LMP_i^{EC} + LMP_i^{LC} + LMP_i^{CC} + LMP_i^{NC}$$

Where:

EC stands for the energy component,
LC stands for the loss component,
CC stands for the competitive constraint congestion component (Competitive LMP), and;
NC stands for the non-competitive constraint congestion component.

Under the LMP decomposition method, a positive non-competitive congestion component indicates the potential of local market power. The non-competitive congestion component of each LMP will be calculated as the sum over all non-competitive constraints of the product of the constraint shadow price and the corresponding shift factor.

In order for the non-competitive congestion component to be an accurate indicator of local market power, the reference bus that these shift factors relate to should be at a location that is least susceptible to the exercise of local market power. The CAISO selects as the reference bus the Midway 500kV bus when flow on Path 26 is north to south and the Vincent 500kV bus when flow on Path 26 is south to north. The Midway and Vincent 500kV buses are excellent choices for LMPM purpose because they are located on the backbone of the CAISO's transmission system near the center of the California transmission grid with sufficient generation and roughly half the system load on each side. Therefore, these buses are very competitive locations, and are least likely to be impacted by the exercise of local market power.

Every resource with the LMP non-competitive congestion component greater than the Mitigation Threshold Price (currently set at zero) is subject to mitigation. Bids from any such resources will be mitigated downward to the higher of the resource's Default Energy Bid, or the "competitive LMP" at the resource's location, which is the LMP established in the LMPM run minus the non-competitive congestion component thereof (competitive LMP = $LMP_i - LMP_i^{NC}$).

6.5.2   Treatment of RMR Resources in MPM

RMR dispatches are determined in accordance with the RMR Contract, the MPM process addressed in Sections 31 and 33 of the CAISO Tariff and through manual RMR Dispatch Notices to meet local reliability requirements. To manage RMR resources within RMR Contract requirements and limitations, the CAISO may rely on manual RMR dispatches exclusively. Except as discussed in Section 6.5.1 above for RMR Units located in the San Diego Air Quality Control Basis with binding emissions constraints, RMR units operating under Condition 1 that will be manually dispatched by the CAISO for RMR services will be able to participate in the market like non-RMR Units.

CAISO notifies SCs for RMR Units of the amount and time of the Energy requirements from specific RMR Units in the Trading Day either prior to or at the same time as the Day-Ahead Schedules, AS and RUC Awards are published. This notification occurs via an RMR Dispatch Notice or a flagged RMR Dispatch in the IFM Day-Ahead Schedule.

CAISO may also issue RMR Dispatch Notices after Market Close of the DAM and through Dispatch Instructions flagged as RMR Dispatches in the Real-Time Market. The Energy to be delivered for each Trading Hour pursuant to the RMR Dispatch Notice an RMR Dispatch in the IFM or Real-Time is referred to as the "RMR Energy." SCs may submit Bids in the DAM or the HASP for RMR Units operating under Condition 1 of the RMR Contract, in accordance with the bidding rules applicable to non-RMR Units.

A Bid submitted in the ISO markets on behalf of a Condition 1 RMR Unit is deemed to be a notice of intent to substitute a Market Transaction for the amount of MWh specified in each Bid for each Trading Hour pursuant to Section 5.2 of the RMR Contract. In the event CAISO issues an RMR Dispatch Notice or an RMR Dispatch in the IFM or Real-Time Market for any Trading Hour, any MWh quantities not subject to mitigation as a result of the MPM process are settled as a market transaction under the RMR Contract.

RMR Units operating under Condition 2 may not submit Bids until and unless CAISO issues an RMR Dispatch Notice or unless the resource is flagged as an RMR Dispatch in the DAM, in which case the RMR Contracts requires consideration of RMR Proxy Bids on behalf of the remaining capacity of the resource in the subsequent markets.

6.5.3   Competitive Path Criteria

This is based on CAISO Tariff Sections 39.7.2.2 and 39.7.3.

As part of each MPM run, an in-line dynamic competitive/non-competitive designation calculation (dynamic competitive path assessment or DCPA) determines whether a constraint is non-competitive. A Transmission Constraint will be competitive by default unless the Transmission Constraint is determined to be non-competitive as part of this calculation. This will occur when the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow.

If, for some reason, the DCPA is unable to function, the MPM will rely on a default competitive path list which is compiled based on historical analysis of congestion and previous DCPA results on each Transmission Constraint.

For a detailed process description for the competitive path criteria, Refer to Attachment B.

6.5.4   Default Energy Bids

This section is based on CAISO Tariff Section 39.7.1, Calculation of Default Energy Bids.

Default Energy Bids are calculated for on-peak hours and off-peak hours, pursuant to one of the methodologies described in this Section. The SCs for each Generating Unit owner or Participating Load must rank the following options of calculating the Default Energy Bid starting with their preferred method. The SC must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the SC must have a Negotiated Rate established with the Independent Entity charged with calculating the Default Energy Bid. If no rank order is specified for a Generating Unit or Participating Load, then the following default rank order is applied:

1. Variable Cost Option (see CAISO Tariff Section 39.7.1.1)

2. Negotiated Rate Option (see CAISO Tariff Section 39.7.1.3)

3. LMP Option (see CAISO Tariff Section 39.7.1.2)

4. Variable Cost Option plus Bid Adder (see CAISO Tariff Section 39.7.1.4)

The details of this calculation are described in more detail in the *BPM for Market Instruments, Attachment D.*

6.5.5   Bid Adder for Frequently Mitigated Units

This section is based on CAISO Tariff Section 39.8.1, Bid Adder Eligibility Criteria.

To receive a Bid Adder for Frequently Mitigated Units, a Generating Unit:

  ➢ Must have a Mitigation Frequency that is greater than 80% in the previous 12 months

  ➢ Must have run for more than 200 hours in the previous 12 months

  ➢ Must not have an contract to be a Resource Adequacy Resource for its entire Maximum Net Dependable Capacity or be subject to an obligation to make capacity available under the CAISO Tariff

Additionally, the SC for the Generating Unit must agree to be subject to the Frequently Mitigated Unit Option for a Default Energy Bid. Run hours are those hours during which a Generating Unit has positive metered output.

Generating Units that received RMR dispatches and/or incremental Bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of MRTU have that hour counted as a mitigated hour in their Mitigation Frequency. After the first 12 months from the effective date of MRTU, the Mitigation Frequency is based entirely on a Generating Unit mitigated under the MPM process described in Sections 31 and 33 of the MRTU CAISO Tariff.

6.6   Integrated Forward Market

This section is based on CAISO Tariff Section 31.3, Integrated Forward Market.

After the MPM and prior to RUC, CAISO performs the IFM. The IFM performs Unit Commitment and Congestion Management, clears Virtual Bids submitted by SCs and clears the Energy Bids as modified in the MPM, taking into account transmission limits, inter-temporal and other operating constraints, and ensures that adequate Ancillary Services are procured in the CAISO Balancing Authority Area based on 100% of the CAISO Forecast of CAISO Demand.

The IFM:

  ➢ Determines Day-Ahead Schedules and AS Awards, and related LMPs and ASMPs

  ➢ Optimally commits resources that bid in to the DAM. The IFM performs an SCUC process which utilizes Mixed Integer Programming (MIP) algorithm using the multi-part Supply Bids (including a Start-Up Bid, Minimum Load Bid, and Energy Bid Curve), and a

capacity Bid for Ancillary Services as well as Self-Schedules submitted by SCs. The IFM also optimally schedules resources subject to their hourly Capacity Limits, and Use-Limited Resources subject to their submitted Daily Energy Limits. When making a commitment decision in IFM, consistent with the consideration of a resource's minimum up time that extends beyond the IFM trading day time horizon, the minimum load costs that extend beyond the IFM trade day horizon up to the resources minimum up time may also be considered.

➤ For a Multi-Stage Generating Resource, the IFM produces a Day-Ahead Schedule for no more than one MSG Configuration per Trading Hour. In addition, the IFM will produce the MSG Transition and the MSG Configuration indicators for the Multi-Stage Generating Resource, which would establish the expected MSG Configuration in which the Multi-Stage Generating Resource will operate. During a MSG Transition, the committed MSG Configuration is considered to be the "from" MSG Configuration.

➤ For Non-Dynamic System Resources, Energy and Ancillary Services awards are rounded to an integer value in order to comply with regional scheduling practices. The rounding will be performed in a way that the aggregate of schedules on an intertie do not violate the intertie limit.

6.6.1   IFM Inputs

In addition to the data identified in earlier sections of this BPM, this section lists those inputs that are particularly important in IFM:

➤ Ancillary Services requirements from AS requirements setter (see Section 4.2, Ancillary Services Requirements)

➤ Default LAP and Custom LAP Load Distribution Factors (see Section 3.1.4, Load Distribution Factors)

➤ Generation Distribution Factors (see Section 3.1.2, Generation Distribution Factors)

➤ Transmission constraints

➤ Generation Outages (see *BPM for Outage Management*)

➤ Daily total Energy Limits

➤ TOR/ETC capacity (see Section 5.2, Existing Transmission Contract Calculator)

6.6.1.1   Bids Usage & Treatment in IFM

The following Bids are considered in IFM:

> ➤ Energy Bids (multi-segment)
> - Three-part Energy Bids for Generating Resources (including Aggregate Generating Resources with specified Generation Distribution Factors)
>
> - Three-part Energy Bids for logical generators that represent Participating Loads in association with fixed (i.e., Price Taker), non-conforming Load Schedules
>
> - One-part Energy Bids for non-Participating Loads (including aggregated Loads with specified Load Distribution Factors)
>
> - One-part Energy Bids for System Resources (imports and exports)
>
> - One-part Energy Bids for Virtual Supply or Virtual Demand.

Three-part Energy Bids consist of Start-Up Cost (up to three segments), Minimum Load Cost (single value), and incremental Energy Bid (up to ten segments).

If the first Energy Bid MW breakpoint is higher than the Minimum Load, then there must be submitted Self-Schedules that add up to that MW level. The Self-Schedules between the Minimum Load and the first Energy Bid MW breakpoint are subject to uneconomic adjustments for Congestion Management based on artificial prices (penalties) that reflect various scheduling priorities, such as RMR pre-dispatch, TOR and ETC Self-Schedules.

Since Virtual Bids can be submitted per Eligible PNode/APNode for each eligible SC ID, in order to manage the volume of Virtual Bids into the IFM optimization, the following methodology will be utilized in SIBR and the IFM:

At the Day-Ahead Market close (currently 10:00 a.m.) the application will aggregate the Virtual Bids at each Eligible PNode/APNode to create one aggregate Virtual Supply Bid and one aggregate Virtual Demand Bid at each location (the aggregate bid can contain many more than 10 segments). For aggregation of Bids, the application will follow the standard of stacking up Bid segments when Energy Prices are different while adding MWs if Energy Prices are the same.

After the day-ahead application completes, the cleared Virtual Bid results will be de-aggregated at the eligible SC ID level before the Day-Ahead Market results, which include Virtual Awards, are published to Market Participants. For de-aggregation of a non-marginal segment, it is straight forward to assign the individual cleared MW to the eligible SCID. For the marginal

segment, the relevant MW cleared amount may be associated with multiple bid segments and hence a prorating is needed to obtain the individual cleared MW amount at the SCID level. The CAISO will prorate the awarded MWs proportional to the submitted MWs of the marginal segment of each Virtual Bid contributing to the marginal aggregate segment.

- ➢ AS Bids (single capacity segment)
    - ▪ Regulation Up Bids (single segment capacity and price, single segment opportunity cost, and single segment Mileage price)
    - ▪ Regulation Down Bids (single segment capacity and price, single segment opportunity cost, and single segment Mileage price)
    - ▪ Spinning Reserve Bids
    - ▪ Non-Spinning Reserve Bids

AS may be simultaneously Self-Provided and Bid. AS Self-Provision from Non-Dynamic System Resources can be accomplished by submitting AS Bids at 0 $/MWH. AS exports are not allowed in the CAISO Markets.

6.6.1.1.1 Minimum Load Cost (MLC) adjustment under minimum load (Pmin) re-rate

If the Pmin of a resource or the Pmin of an MSG configuration is re-rated to a higher MW level than registered in Master File, the CAISO market systems consider the energy cost under the re-rated Pmin by adjusting the MLC to reflect the cost of commitment under the re-rated Pmin level. When optimizing MSG resources, the CAISO market will use the Default Energy Bid (DEB) associated with the resource to represent the actual cost of re-rating a configuration's Pmin with a Pmin re-rate. The DEB integration formula, shown below, is used to calculate the MLC' using the DEB integration method. The resulting MLC' will be used in commitment decisions by the market systems and in Bid Cost Recovery settlement (see next section).

DEB Integration Formula

$$MLC' = MLC + \int_{P_{min}}^{P_{min}'} DEB(p)dp$$

MLC'   Minimum load cost of the re-rated Pmin level

MLC   Minimum load cost of the original bid-in minimum load cost

DEB(p)   Default energy bid cost associated with the actual cost of re-rating a resource or MSG configuration's Pmin

dp   Change in energy

6.6.1.2 IFM Uplift Costs

The IFM Bid Cost for a given resource is due to the Start-Up Cost, Minimum Load Cost, Transition Costs, and Energy and Ancillary Services bid costs that are not otherwise recovered

from the revenues associated with the IFM Energy and Ancillary Services markets. The IFM Bid Cost for all resources is recovered through the IFM Bid Cost Uplift.

The responsibility for the IFM Bid Cost Uplift can be transferred via Inter-SC Trades of IFM Load Uplift Obligation. It is important to understand that the responsibility for the IFM Bid Cost Uplift does not automatically transfer from one SC to another SC as a result of an Inter-SC Trade for Energy. Rather, if the agreement between the two trading SC's includes a provision that the IFM Bid Cost Uplift responsibility is to be transferred from the Energy buyer to the Energy seller, then a separate Inter-SC Trade of IFM Bid Cost Uplift must be submitted between the trading SCs.

Additional information on Bid Cost Recovery is given in the *BPM for Settlements & Billing*.

6.6.2   IFM Constraints & Objectives

Resources are committed and scheduled in the IFM for each Trading Hour of the Trading Day. Self-committed resources with Self-Schedules and/or Self-Provided AS are modeled as "must run" in the relevant Trading Hours. RMR resources pre-dispatched manually before the DAM are also modeled as "must run" in the relevant Trading Hours with an RMR Self-Schedule at the applicable RMR level. Resources bidding in the market with 1) no startup or minimum load costs, 2) zero Pmin, and 3) zero startup time are considered always on-line from a commitment standpoint unless they have an Outage. These resources (NGRs by nature or resources registered this way in the Master File) are automatically available to receive an award of energy and/or AS unless there is an Outage.

Resources with Outages are modeled as "unavailable" in the relevant Trading Hours. Resources with multi-part Energy Bids and/or AS Bids, but without Self-Schedules or Submissions to Self-Provide an AS are modeled as "cycling" in the relevant Trading Hours, which means that these resources are available for optimal commitment in these hours, subject to applicable inter-temporal constraints and initial conditions.

The following ramping rules apply consistently for all DAM applications:

1) The resource's Operational Ramp Rate would always be used to constrain Energy schedules across time intervals irrespective of Regulation Awards. The Operational Ramp Rate may vary over the resource operating range and it incorporates any ramp rates over Forbidden Operating Regions. The fixed Regulating Ramp Rate would only be used to limit Regulation awards.

2) Hourly Intertie resource schedule changes would not be limited across hours.

3) The upward and downward ramp capability of online resources across time intervals would be limited to the duration of the time interval: 60min in DAM.

4) The upward and downward ramp capability of resources starting up or shutting down across time intervals (from or to the applicable Lower Operating Limit) would be limited to half the duration of the time interval: 30min in DAM.

5) The upward and downward ramp capability of resources across time intervals would not be limited by capacity limits (operating or regulating limits); in that respect, the upward ramp capability would extend upwards to $+\infty$ and the downward ramp capability would extend downwards to $-\infty$ by extending the last and first segments of the Operational Ramp Rate curve beyond the resource Maximum Capacity and Minimum Load, respectively. Capacity limits would be enforced separately through the capacity constraints.

6) The upward ramp capability of resources across time intervals with Regulation Up awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

7) The downward ramp capability of resources across time intervals with Regulation Down awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor (same as above).

8) For each MSG Configuration, the Operational Ramp Rate curve is limited to two segments. These ramp rates will be used to determine the ramp capacity when the Multi-Stage Generating Resource is within the relevant configuration. The ramp time that it takes to transition from one configuration to another configuration is defined as the Transition Time per directional transition in the Transition Matrix.

These ramping rules result in a consistent unified treatment across all applications. Conditional ramp limits apply only to resources with Regulation awards. No ramp capability reduction is required for Spinning or Non-Spinning Reserve awards given that these awards are normally dispatched by RTCD where all ramp capability must be made available even at the expense of Regulation.

For resources with two regulating ranges, the IFM (and all other DAM applications) will use a single regulating range from the lower regulating limit of the first (low) regulating range to the upper regulating limit of the second (high) regulating range. This conservative approach is adopted because the ultimate regulating range within which the resource will operate in Real-Time is not known in advance in the DAM.

Also, CAISO will limit Operational Ramp Rate changes from one operating range to next operating range to a maximum 10:1 ratio. CAISO will internally adjust ramp rates to achieve a 10:1 ratio if submitted ramp rates exceed this ratio.

The Time Horizon of the IFM optimization is shown in Exhibit 6-1.

6.6.2.1   Multi-Stage Generating Resources in the Day-Ahead Market

➢ The IFM will dispatch Multi-Stage Generating Resources at the MSG Configuration level, determining the optimal MSG Configuration. Exceptional Dispatches, i.e., manual dispatches, will dispatch to a value for the specific Multi-Stage Generating Resources, but do not specify the particular MSG Configuration.

➢ The initial status for Multi-Stage Generating Resources is based on the registered individual MSG configurations and not at the Generating Unit or Dynamic Resource-Specific System Resources level (i.e., plant level). An MSG Configuration that is awarded in RUC at the end of previous Trading Day will receive from the CAISO their on-line initial status and corresponding initial MW for the next Trading Day. If there is no RUC Award for a Multi-Stage Generating Resource, then the MSG Configuration that was scheduled in IFM at the end of previous Trading Day will have the on-line initial status for the next Trading Day. Otherwise all the MSG Configurations would be treated as initially offline.

➢ Since Self-Provided Ancillary Services can be submitted only at the MSG Configuration for a given Trading Hour and since it is possible that that Multi-Stage Generating Resource can actually support the Self-Provided Ancillary Service amount from other configurations, Self-Provided Ancillary Service quantities are treated as plant level quantities in the Integrated Forward Market. In order to accomplish this, the Self-Provided Ancillary Services on the originally submitted MSG Configuration is propagated to other Ancillary Services certified MSG Configurations for the optimization to consider in the following steps:

Step 1: Perform the Ancillary Services qualification process on the submitted MSG Configuration in the same manner as for non-Multi-Stage Generating Resources, except using the MSG Configuration's parameters such as ramp-rate, Minimum Load and PMax.

Step 2: Transfer the qualified Ancillary Services self provision MW to other MSG Configurations with Ancillary Services certification in the same service product if these configurations have Energy Bids for that given Trading Hour. This transferred Ancillary

Services self provision MW is determined by the following formula per transferred MSG Configuration,

> Transferred Self-Provided Ancillary Services = Minimum (final qualified Self-Provided Ancillary Service of bid in MSG Configuration, certified Ancillary Services capacity of transferred MSG Configuration)

Step 3: On the transferred MSG Configuration, the transferred Self-Provided Ancillary Services amount determined from step 2 will then be further qualified using the same rules in capacity and ramping qualification as for non-Multi-Stage Generating Resources (see section 4.2.1), except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

➢ The Multi-Stage Generating Resource will be allowed to submit a Self-Schedule on only one MSG Configuration per given Trading Hour. However, this Self-Schedule reflects the Multi-Stage Generating Resource's intention to operate at or no lower than a certain MW level, not an intention to operate in a particular MSG Configuration. Consequentially, any one of the MSG Configurations may be committed if there is a self-schedule on any of the MSG Configurations within the same Multi-Stage Generating Resource.   Once submitted, the Self-Schedule is associated with all MSG Configurations of the Multi-Stage Generating Resource that have a Minimum Load below or equal to the Self-Schedule quantity. In order to provide for fair economic choice among MSG Configurations there will be adjustments to Start-Up Cost, Minimum Load Cost and related Transition Costs of affected configurations as listed below.

The rules given below apply to self-schedules:

1. For the MSG Configuration with a PMin higher than the Self-Schedule MW:

    • The Minimum Load Cost will be taken into account when considering commitment of the configuration, but will be reduced to only reflect cost of minimum load not consumed by Self-Scheduled quantity, i.e. will be equal to Max(0, Minimum Load Cost of the transferred configuration - Minimum Load Cost of the submitted MSG Configuration);

    • the Start-Up Cost will be taken into account when considering commitment of the MSG Configuration;

    • Transition Cost for any transition that is incident (incoming or outgoing) into/from the MSG Configuration will be considered unless conflicting with rules 2 and 3 below.

2. For the MSG Configuration with a PMin lower than or equal to the Self-Schedule MW and a PMax higher than or equal to the Self-Schedule MW:

- Start-Up Costs and Minimum Load Costs are treated as must-run resources (i.e. there is no Start-Up Cost and no Minimum Load Cost);

- Ignore Transition Costs for incoming transitions;

- Consider Transition Costs for outgoing transitions.

3. For the MSG Configuration with a PMax lower than the Self-Schedule MW:

- Ignore Start-Up Costs;

- Minimum Load Cost treatment is the same as in (2) above;

- Ignore Transition Cost for any transition incident to the particular configuration.

6.6.2.2   Group Constraint

The group constraint enforces a minimum time delay between two successive startups or two successive shutdowns within a group of resources. The minimum time delays will be enforced between any pair of resources within the group and no ordering is assumed among the resources in the group. There is no upward limit to the minimum time delay setting.

This constraint can be used for both generating and pump storage resources. Market Participants may define any set of their resources as a group, as long as the constraint represents an actual physical limitation of the group.

6.6.2.3   Stored Energy Management

The NGR model applies to resources that are subject a limited energy constraint to provide energy and ancillary services. NGRs such as flywheels, batteries, and some demand response resources require a real-time energy offset; whereas, a traditional hydro or thermal unit does not.

An NGR will be subject to the capacity and operation range limits similar to a generator. However, the NGR operating range can be negative. The negative production from a NGR reflects the fact that the NGR can withdraw energy from the grid. In addition, the ability of an NGR to provide energy and ancillary services will depend on the NGRs' stored energy level and the resource's ramp (charge/discharge) rate.   Under the NGR model, the ability to provide energy is also dependent on a resource's efficiency rating, which is the percentage of charging energy that, after losses, is ultimately available for generation.

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) 2.5 MWh and a lower charge limit (LCL) 0 MWh, Pmax = 10 MW, and Pmin = -10MW. When these limits are provided to the ISO, they 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.

$$SOC(T) = SOC(T-1) - \int_{T-1}^{T} GEN(t) * dt$$

The energy schedule and ancillary service awards are subject to SOC constraints and capacity constraints.

Exhibit 6-3: Relationship between state of charge and generation in a LESR
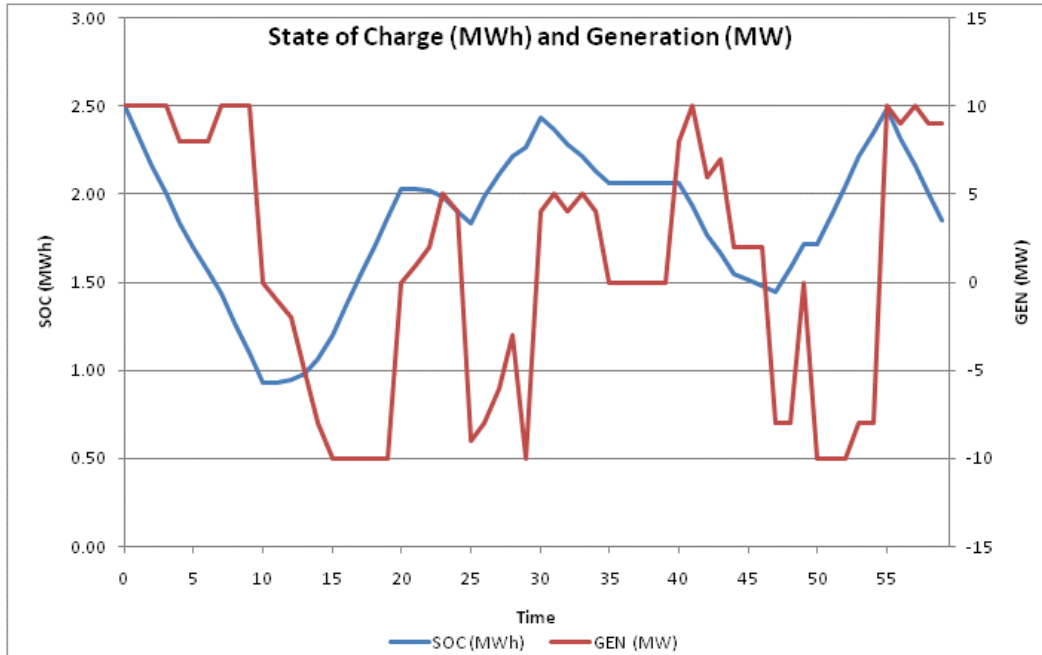
To account for energy constraints inherent in the NGR resource, the following constraints will be enforced in the market. These are in addition to constraints applied to generators which also apply to NGRs.

- For NGRs electing not to use Regulation Energy Management their optimal schedule and AS awards shall be limited by the available stored energy (State of Charge, SOC) between the lower charge limit and upper charge limit.

- The SOC constraint shall be observed on a continuous basis, per interval in IFM and for binding and advisory intervals in real-time.

Since resources using Regulation Energy Management only participate in the regulation market, the SOC constraint for these resources is not enforced in IFM.

6.6.2.4   Minimum Online Commitment Constraint

The ISO has constraint modeling capability in the IFM and RTM to address the operational needs of operating procedures that require a minimum quantity of committed online resources in order to maintain reliability. These procedures specify requirements for a minimum quantity of online commitment from a specific group of resources in a defined area. This required minimum online commitment does not reflect a minimum energy production or an amount of 10 minute

operating reserve. Rather these requirements are described in terms of a minimum set of online resources, by name or by total quantity of operating capability based on the resources Maximum Operating level (Pmax) or an effective MW equivalent based on the units VAR support and/or location. However, the same set of resources committed in IFM to satisfy the minimum online constraint could also be ready for dispatch or be awarded ancillary services in the market co-optimization.

The ISO has adopted the following minimum online commitment method, which incorporates an additional nomogram type constraint equation capability into the market solution. In general, minimum online generation commitment (MOC) requirement is a constraint binding a group of market resources (generators) by the following relationship:

$$\sum_{i \in G} a_i \, Y_{i,t} \, P_{i,t}^{\max} \geq P_{G,t}^{moc} \qquad \forall t, G \qquad (1)$$

Where:

$P_{G,t}^{moc}$ is the minimum total online commitment required for interval t for the defined set of generating resources G.

a_i is a multiplier representing effectiveness for the resource i in meeting Minimum Online Commitment requirement

$Y_{i,t}$ is the commitment status for market resource i for interval t

$P_{i,t}^{max}$ is the total maximum operating limit of the market resource i and interval t, as derated by SLIC of the resource (if appropriate)

Minimum online commitment requirement (MW) is the minimum total online commitment required for interval t for the defined set of resources able to participate in the satisfying the constraint. This quantity may differ by interval (by hour in DAM) with the amount of load within designated local areas. This formulation recognizes that the variation of required commitment versus the local load may not be linear.

Multiple constraint equations can be defined to incorporate different groups of resources depending on the procedure or outage that is being represented. A resource may participate in more than one minimum online commitment requirement constraint equation. The shadow prices of these constraints are not incorporated directly into any pricing calculations. The expectation is that adding these constraint equations will commit an appropriate set of resources that satisfies the minimum amount of commitment online required in the market processes to satisfy the operating procedural and outage requirements. If the constraint cannot be satisfied, the constraint will be violated at some configurable penalty value in the market optimization that is set to avoid under-procurement when resources are indeed available.

In addition to operating procedures, use of this functionality may also be considered for equipment outages that have a commitment requirement to return the system to normal steady state limits following contingencies or a commitment requirement to provide the necessary voltage and/or other system support.

For users who have access to Protected Data under Tariff section 6.5.10.1, the CAISO posts the MOC definitions used in the Day Ahead Market prior to the Day Ahead Market bidding deadline if possible, with the requirements posted three days afterwards. See the *Business Practice Manual for Market Instruments* for more information. Ongoing MOC enforcements are usually identified with the associated four digit procedure number, for example "ANYWHERE 7000". MOC enforcements related to equipment outages are usually identified with the associated outage number, for example "MOC ANYWHERE 22345678". In cases where an

equipment outage MOC affects a large number of generating resources or where the duration is for an extended period, and the MOC requirement is known in advance, the CAISO may post a Market Notice as a courtesy to market participants. The CAISO will post a Market Notice for any new procedure-related MOC prior to the first day of enforcement.

6.6.2.5 Enforcement of Constraints on the Interties

The CAISO enforces both scheduled and physical flows on the Interties through the use of a two-constraint approach. In the IFM, the ISO will continue to enforce a scheduling constraint and will include a physical flow constraint (based on the FNM expansion initiatives), each of which will consider both physical and Virtual Bids. To ensure uniqueness of prices intertie constraints, similar to other transmission constraints, are formulated with additional slack variables. The scheduling constraint will continue to be based on the assessment of Intertie Bids submitted by the Scheduling Coordinators relative to the Available Transfer Capability of the specific Intertie location. This will ensure that contract paths are honored and will be used for ~~E-Tag~~E-Tagging intertie schedules. The physical flow constraint will be based on the modeled flows for the Intertie, taking into account the actual power flow contributions from all resource schedules in the Full Network Model against the Available Transfer Capability of the Intertie. Unlike the scheduling constraint, the contributions of intertie schedules towards the physical flow limit will be based on the shift factors calculated from the network model, which reflects the amount of flow contribution that change in output will impose on an identified transmission facility or flowgate. Each Intertie will have a single Total Transfer Capability and the scheduling limit and physical flow limit will be compared against the Intertie's capacity. The scheduling limit and physical flow limit are not necessarily equal to each other.

In the Residual Unit Commitment, the CAISO will enforce two constraints that only consider physical awards with respect to contract path limits

(*i.e.*, Virtual Awards cannot provide counterflow to physical awards).

6.6.3   Co-optimization of Energy & Ancillary Services

The SCs submit AS Bids in the DAM and the IFM considers AS Bids in conjunction with Energy Bids to make AS Awards based on a simultaneous optimization that minimizes the total Bid Cost of clearing Congestion, balancing physical Energy and Virtual Supply and Demand, and reserving unloaded capacity to provide AS.

The optimization process can substitute higher-quality AS products for lower quality AS products. For example, it may reserve additional Spinning Reserves to cover part or all of the Non-Spinning Reserve requirements.

For purposes of the Day-Ahead AS procurement, all RA resources certified to provide Ancillary Services are deemed available to CAISO.

An important feature of the integration of AS with Energy and Congestion Management in the IFM is the ability of the IFM to optimally utilize import/export transmission capacity to import Energy and AS. Import of Regulation Down utilizes export transmission capacity. The IFM utilizes import transmission capacity for the most economically efficient combination of Energy and AS. AS does not create net counterflow against energy use of transmission capacity.

6.6.4   Market Clearing

Exhibit 6-3 illustrates the Market Clearing Price for Energy resulting from IFM, with the simplifying assumption that there are no Marginal Losses and that there is no Congestion. Under this scenario all the LMPs have the same value in $/MWh as the Market Clearing Price.

The Supply curve (actually steps) represents the "merit order" of the Generating Unit Bids from lowest to highest $/MWh, starting at the total Self-Scheduled Supply MW. The Demand curve (actually steps) represents the Demand Bids from highest to lowest $/MWh, starting at the total Self-Scheduled Demand MW. The intersection of these two curves is defined as the Market Clearing Price (MCP) for the total demand scheduled.

All scheduled Generating Units are paid the MCP and all scheduled Loads are charged the MCP.

Exhibit 6-4: Day-Ahead Market Clearing Price for Energy – Ignoring Marginal Losses & Congestion
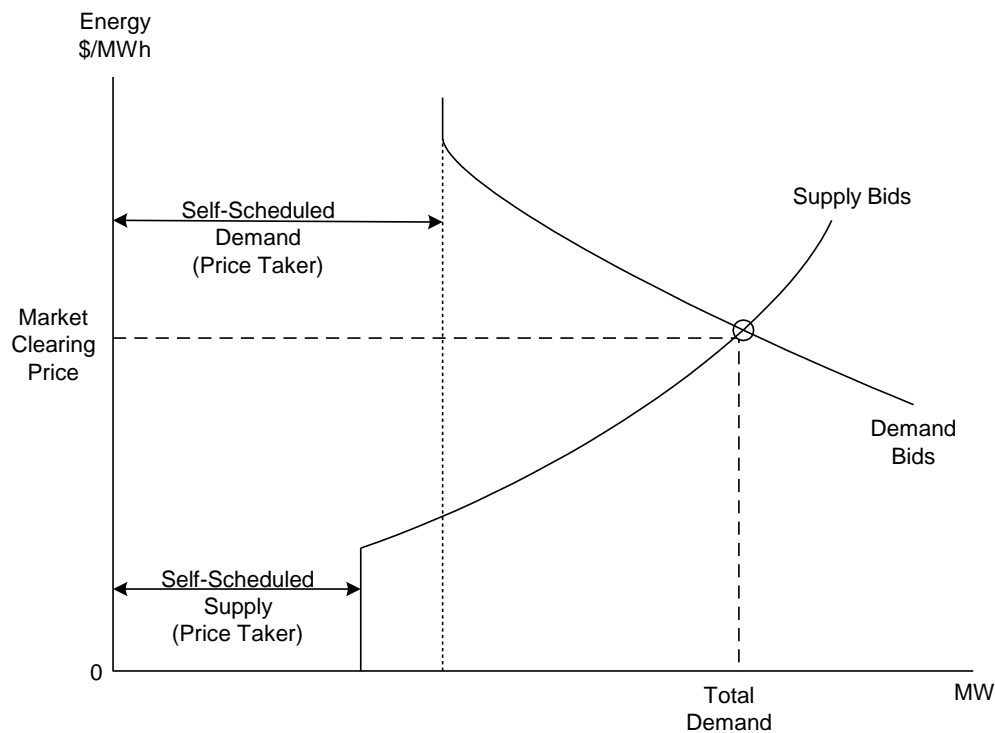
In the general case where Transmission Losses and Congestion are present, the market clearing is a more complicated process that yields different LMPs at each network node.

6.6.5   Adjustment of Non-Priced Quantities in IFM

This section is based on CAISO Tariff Section 31.4, Uneconomic Adjustments in the IFM.

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point is subject to adjustments based on the scheduling priorities listed in Section 6.6.5.3.

Through this process, imports and exports may be reduced to zero, Demand Schedules may be reduced to zero, and Price Taker Demand (LAP Load) may be reduced. However, prior to reducing Load the following process is used to ensure that LAP Load is not reduced unnecessarily.

Market Parameter Values

This section provides the specific value settings for a set of ISO market parameters that are used for adjusting non-priced quantities in the market optimizations.

The parameter values are organized into three sections by market process: the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC), and the Real Time Market (RTM). The parameters in these tables are also known in the jargon of mathematical optimization as "penalty factors," which are associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values in the tables for each market reflect the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software.

Integrated Forward Market (IFM) Parameter Values

Penalty Price Description	Scheduling Run Value[27]	Pricing Run Value	Comment
Market energy balance	6500	1000	Market energy balance is the requirement that total supply equal the sum of total demand plus losses for the entire system. In the IFM energy balance reflects the clearing of bid-in supply and demand; in the MPM component of the DAM it reflects the scheduling of bid-in supply against the ISO demand forecast.
Transmission constraints: Intertie scheduling	5000	1000	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply)	-6000	-150	The ISO considers transmission constraints when determining RMR scheduling requirements. After the ISO has determined the RMR scheduling requirements, the market optimization ensures that the designated capacity is scheduled in the market.
Pseudo-tie layoff energy	-4000	-150	Pseudo-tie layoff energy is scheduled under contractual arrangements with the Balancing Authority in whose area a pseudo-tie generator is located.

---

[27]   Penalty values are negatively valued for supply reduction and positively valued for demand reduction.

Penalty Price Description	Scheduling Run Value[27]	Pricing Run Value	Comment
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	5000	1000	In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Transmission Ownership Right (TOR) self schedule	5900, -5900	1000, -150	A TOR Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints.
Existing Transmission Contract (ETC) self schedule	5100 to 5900, -5100 to -5900	1000, -150	An ETC Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints. The typical value is set at $5500, but different values from $5100 to $5900 are possible if the instructions to the ISO establish differential priorities among ETC rights. For some ETC rights the ISO may use values below the stated scheduling run range if that is required for consistency with the instructions provided to the ISO by the PTO.
Converted Right (CVR) self schedule	5500, -5500	1000, -150	A CVR Self-Schedule is assigned the same priority as the typical value for ETC Self-Schedules.
Ancillary Service Region Regulation-up and Regulation-down Minimum Requirements	2500	250	In the event of bid insufficiency, AS minimum requirements will be met in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
Ancillary Service Region Spin Minimum Requirements	2250	250	Spinning reserve minimum requirement is enforced with priority lower than regulation up minimum requirement in scheduling run.
Ancillary Service Region Non-Spin Minimum Requirements	2000	250	Non-spin reserve minimum requirement is enforced with priority lower than spin minimum requirement in scheduling run.

Penalty Price Description	Scheduling Run Value[27]	Pricing Run Value	Comment
Ancillary Service Region Maximum Limit on Upward Services	1500	250	In the event of multiple AS regional requirements having bid insufficiency, it is undesirable to have multiple constraints produce AS prices equaling multiples of the AS bid cap. An alternative way to enforce sub-regional AS requirements is to enforce a maximum AS requirement on other AS regions, thereby reducing the AS prices in the other regions without causing excessive AS prices in the sub-region with bid insufficiency.
Self-scheduled CAISO demand and self-scheduled exports using identified non-RA supply resource	1800	1000	Pursuant to section 31.4, the uneconomic bid price for self-scheduled demand in the scheduling run exceeds the uneconomic bid price for self-scheduled supply and self-scheduled exports not using identified non-RA supply resources.
Self-scheduled exports not using identified non-RA supply resource	1150	1000	The scheduling parameter for self-scheduled exports not using identified non-RA capacity is set below the parameter for generic self-schedules for demand.
Regulatory Must-Run and Must Take supply curtailment	-1350	-150	Regulatory must-run and must-take supply receive priority over generic self-schedules for supply resources.
Price-taker supply bids	-400	-150	Generic self-schedules for supply receive higher priority than Economic Bids at the bid floor.
Conditionally qualified Regulation Up or Down self-provision	-405	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 received higher priority to maintaining the availability of regulation, over spinning and non-spinning reserve.
Conditionally qualified Spin self-provision	-400	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 receives higher priority to maintaining the availability of spinning reserve, over non-spinning reserve.
Conditionally qualified Non-Spin self-provision	-395	NA	This penalty price for conversion of self-provided non-spinning reserves balances the maintenance of AS self-schedules with ensuring that the conversion to energy occurs before transmission constraints are relaxed.

Penalty Price Description	Scheduling Run Value[27]	Pricing Run Value	Comment
Conditionally unqualified Reg Up or Down self-provision	-195	NA	In instances where AS self-provision is not qualified pursuant to the MRTU tariff, the capacity can still be considered as an AS bid, along with regular AS bids. The price used for considering unqualified AS self-provision is lower than the AS bid cap, to allow it to be considered as an Economic Bid.
Conditionally unqualified Spin self-provision	-170	NA	Same as above.
Conditionally unqualified Non-Spin self-provision	-155	NA	Same as above.

Residual Unit Commitment (RUC) Parameter Values

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Transmission constraints: Intertie scheduling	2000	250	The Intertie scheduling constraint retains higher relative priority than other RUC constraints.
Market energy balance - under procurement	1600	0	The RUC procurement may be less than the Demand forecast if the CAISO has committed all available generation and accepted intertie bids up to the intertie capacity.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
Maximum energy limit in RUC schedule	1500	250	Limits the extent to which RUC can procure energy rather than unloaded capacity to meet the RUC target. For MRTU launch the limit will be set so that the total energy scheduled in the IFM and RUC will be no greater than 99% of the RUC target unless this limit is relaxed in the RUC scheduling run.
Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Day-Ahead energy schedules resulting from the IFM run	250	0	These values preserve schedules established in IFM in both the RUC scheduling run and pricing run.
Market energy balance -over procurement	200	0	Market energy balance when the RUC procurement may be more than the Demand forecast.

Real Time Market Parameters

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Energy balance/Load curtailment and Self-Scheduled exports utilizing non-RA capacity	1450	1000	Scheduling run penalty price is set high to achieve high priority in serving forecast load and exports that utilize non-RA capacity. Energy bid cap as pricing run parameter reflects energy supply shortage.
Transmission constraints: Intertie scheduling	1500	1000	The highest among all constraints in scheduling run, penalty price reflects its priority over load serving. Energy bid cap as pricing run parameter reflects energy supply shortage.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply), and Exceptional Dispatch Supply	-6000	-150	RMR scheduling requirement is protected with higher priority over enforcement of internal transmission constraint in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Pseudo-tie layoff energy	-1500	-150	Same priority of protection as RMR schedule in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1500	1000	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $ of congestion relief in $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage.
Real Time TOR Supply Self	-5900	-150	In RTM, TOR self-schedule scheduling run penalty price is much higher in

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Schedule			magnitude than generic self-schedule but lower than transmission constraint. Energy bid floor is used as the pricing run parameter as any type of energy self-schedule.
Real Time ETC Supply Self Schedule	-5100 to -5900	-150	In RTM the range of penalty prices for different ETCs supply self-schedules are much higher in magnitude than generic supply self-schedules but lower than TOR. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Ancillary Service Region Reg-Up and Reg-Down Minimum Requirements	1450	250	Scheduling run penalty price is below the one for transmission constraint. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Spin Minimum Requirements	1400	250	Scheduling run penalty price is lower than the one for regulation-up minimum requirement. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Non-Spin Minimum Requirements	1350	250	Scheduling run penalty price is lower than the one for spin minimum requirement. Pricing parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Maximum Limit on Upward Services	1200	250	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.
Self-scheduled exports not using identified non-RA supply resource	1150	1000	Scheduling run penalty price reflects relatively low priority in protection as compared to other demand categories. Energy bid cap as pricing run parameter to reflect energy supply shortage.
Final IFM Supply Schedule	-750	-150	Scheduling run penalty price is much higher in magnitude than supply generic self-schedule but lower than ETCs. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Regulatory Must-Run and Must Take supply curtailment	-1400	-150	Scheduling run penalty price reflects the higher priority of regulatory must-run and must-take supply received over generic self-schedules for supply resources. Energy bid floor is the pricing parameter

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
			for all energy supply self-schedules.
Price-taker supply bids	-400	-150	Energy bid floor is the pricing parameter for all energy supply self-schedules.
Qualified Load Following self-provision Up or Down	-8500	0	Scheduling run penalty price reflects the highest priority among all categories of AS self-provision. AS bid floor is used as the pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Reg Up or Down Award	-7750	0	Scheduling run penalty price is higher than the penalty price for energy balance constraint to reflect higher in priority over energy. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Spin Award	-7700	0	Scheduling run penalty price is lower than the one for Reg-up. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Non-spin Award	-7650	0	Scheduling run penalty price is lower than the one for Spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Reg Up or Down Real Time self-provision (RTUC only)	-405	0	Scheduling run penalty price allows the conversion of AS self-schedules to Energy to prevent LMP of local area from rising so high as to trigger transmission constraint relaxation. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Spin self-provision (RTUC only)	-400	0	Scheduling run penalty price is below the one for regulating-up. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Non-Spin self-provision (RTUC only)	-395	0	Scheduling run penalty price is below the one for spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Reg Up or Down Real Time self-provision (RTUC only)	-195	0	In scheduling run, AS self-provision not qualified in pre-processing can still be considered as an AS bid with higher priority in the Energy/AS co-optimization along with regular AS bids. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Spin Real Time self-	-170	0	Same as above.

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
provision (RTUC only)			
Conditionally unqualified Non-Spin Real Time self-provision (RTUC only)	-155	0	Same as above.
System power balance constraint	1100, -155	1000, -155	To reflect the role regulation plays in balancing the system for undersupply conditions when economic bids are exhausted, the ISO allows the system power balance constraint to relax by as much as the seasonal regulation requirement. For over-supply conditions, when economic bids are exhausted, the ISO allows the system power balance constraint to relax to about 10% of the seasonal regulation requirement. The prices are selected to allow for coordinated dispatch of bids that may exist at or near the bid cap, or at or near the bid floor.
Power Balance constraint for individual. EIM areas	1100, -750	1000, -150	Subject to the FERC order granting waiver of tariff sections 27.4.3.2.and 27.4.3.4, and consistent with Section 10.1.6 of the BPM for Energy Imbalance Market, which implement the price discovery mechanism overriding the pricing parameters and yielding the last economic signal under constraint relaxation. The scheduling run parameter is set to -750 for the individual EIM areas to coordinate the relaxation of the EIM power balance constraint during over-generation conditions relative to congestion on non-EIM constraints.
EIM Upward Available Balancing Capacity Range	1200 through 1100	Bid in Prices Range for EIM Participating resource and DEB for EIM Non-Participating	The Penalty Price Range used for the Available Capacity Range prices to maintain the economic merit order reflected in the energy bid prices of the allocated energy bid portions
EIM Downward Available Balancing Capacity	-250 through -350	Bid in Prices Range for EIM Participating resource and DEB for EIM	The Penalty Price Range used for the Available Capacity Range prices to maintain the economic merit order reflected in the energy bid prices of the allocated energy bid portions

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
		Non-Participating	
EIM Transfer Constraint	1500	1000	Penalty price and pricing parameter consistent with the transmission constraint;
EIM Entitlement Rate of Change Constraint (RTD Only)	1500	0	Penalty price aligned with EIM transfer constraint is currently applicable to RTD 5 minute rate of change.

Minimum Effectiveness Threshold

A lower limit on the effectiveness of resources considered for re-dispatch to relieve a congested transmission constraint is necessary to prevent the market software from accepting significant quantities of ineffective low-priced energy bids to achieve a small amount of congestion relief on the constraint. The ISO uses a value of two percent (2%) as the minimum effectiveness threshold for congestion management in the day-ahead and real-time markets. The minimum effectiveness threshold is used in the market power mitigation process for dynamic competitive path assesment and LMP decomposition purposes as well as for congestion management purposes.

Weigthing factor for quadratic slack variables

A weigthing factor associated with quadratic slack variables in the cost minimization problem are also needed for the formulation of the constraints that have an impact on energy prices, such as transmission constraints, to attain conditions for uniqueness of prices. This weigthing factor needs to be sufficiently small to preserve the price signal in conditions where the market needs to rely on constraint relaxations. The CAISO uses a value of 0.0001 as the weigthing factor for the quadratic slack variables in both the day-ahead and real-time markets.

6.6.5.1   Reduction of Self-Scheduled LAP Demand

This section is based on CAISO Tariff Section 31.3.1.2, Reduction of LAP Demand.

In the IFM, to the extent the CAISO Market software cannot resolve a non-competitive transmission constraint utilizing Effective Economic Bids such that Self-Scheduled Load at the LAP level would otherwise be reduced to relieve the constraint, CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 24.7.3 of the CAISO Tariff. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted will be:

- (a) Schedule the Energy from Conditionally Qualified Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as RMR or Resource Adequacy. C Consistent with Section 8.6.2 of the CAISO Tariff, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. Because the Conditionally Qualified Self-Provided Ancillary Services is included in the optimization, this step is automatic. The associated Energy Bid prices will be those resulting from the MPM process.

- (b) Relax the Constraint consistent with Section 27.4.3.1 of the CAISO Tariff, and establish prices consistent with Section 27.4.3.2 of the CAISO Tariff. No Constraints on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

6.6.5.2   Reduction in Generation

Generation may be also reduced to a lower operating (or regulating) limit (or lower regulating limit plus any qualified Regulation Down AS Award or Ancillary Services self-provision, if applicable). Any schedules below the Minimum Load level are treated as fixed schedules and are not subject to adjustments for Congestion Management.

6.6.5.3   Scheduling Priorities

This section is based on CAISO Tariff Section 31.4, Adjustments of Non-priced Quantities in the IFM.

The scheduling priorities for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted) are as follows:

- Reliability Must Run (RMR) pre-dispatch reduction
- Day-Ahead TOR (balanced Demand and Supply reduction)

> ➢ Day-Ahead ETCs (balanced Demand and Supply reduction); Different ETC priority levels are observed based upon global ETC priorities provided to CAISO by the Responsible PTOs
> ➢ Other self scheduled Load reduction subject to Section 31.3.1.2 of the CAISO Tariff, as described in Section 6.6.4.1 of this BPM.
> ➢ Day-Ahead Ahead Regulatory Must Run and Regulatory Must Take reduction Self-Scheduled Supply
> ➢ Other self scheduled Supply reduction
> ➢ Economic Demand and Supply Bids

6.6.6   IFM Outputs

The following IFM output information is produced and is financially and operationally binding:

> ➢ Optimal Unit Commitment status (on/off) over the Time Horizon

> ➢ Type of Unit Commitment status (self-commitment and CAISO-commitment)

> ➢ Optimal Energy Schedule for all resources over the Time Horizon

> ➢ Virtual Supply and Virtual Demand Awards

> ➢ Optimal AS Award for all resources over the Time Horizon

> ➢ The total Energy and AS Bid Cost over the Time Horizon

> ➢ The Start-Up Cost ($) for each Generation resource or minimum curtailment payment ($) for each dispatchable Demand/Curtailable Demand resource during each CAISO-commitment period

> ➢ The Minimum Load Cost ($) for each Generation resource or minimum hourly payment ($) in each hour during each CAISO-commitment period

> ➢ The Start-Up Cost/Bid function ($, Minute) or minimum curtailment payment ($) used for each resource in each CAISO-Commitment Period.

> ➢ LMPs for each price Location including all resources; also LMP components (Energy, Marginal Loss, and Congestion components)

> ➢ RASMP for each AS Region

> ➢ ASMP for all resources providing Ancillary Services.

➢ Resources at their effective minimum or maximum MW in each time interval

➢ The level of control and Constraint priority used in obtaining the solution. This informs the CAISO's operator as to how much of uneconomic Bid segments and/or Constraint violations were necessary to solve the optimization.

➢ Amount of any relaxed constraint violations, i.e., the extent to which any constraint was relaxed (in MW) in order to solve the optimization.

6.6.7   Energy Settlement

Scheduling Coordinators on behalf of Generating Units, System Resources, and physical Supply Resources are paid for their Energy Schedule the LMP at their Location. Scheduling Coordinators on behalf of Non-Participating Load and export resources are charged for their Energy Schedule at the LMP at the corresponding LAP or Scheduling Point. Virtual Supply Awards are paid the Day-Ahead LMPs at their location and charged in Real-Time at the applicable FMM LMPs at the applicable PNodes or APNodes. Virtual Demand Awards are charged the Day-Ahead LMPs at their locations and paid in Real-Time at the applicable FMM LMPs at the applicable PNodes or APNodes. The LMP at an aggregate Location for an aggregate resource is an aggregate LMP. The net revenue from these payments and charges is attributed to Marginal Losses and Congestion and is allocated as described in the *BPM for Settlements & Billing*.

The Marginal Cost of Congestion (MCC) for the balanced portion of TOR and ETC Self-Schedules that clear the IFM is rebated to the designated SC for the relevant TOR or ETC. This rebate is calculated as the algebraic difference (it may be negative) between the MCC components at the financial sink and the financial source of the TOR or ETC, multiplied by the scheduled TOR or ETC MW. The financial source and sink of a TOR or ETC are registered Locations in the Master File and may be aggregate with associated distribution factors.

The financial source and the financial sink of a TOR or ETC may be different than the physical source and the physical sink of that TOR or ETC, but nonetheless, they are also registered Locations in the Master File and they may also be aggregate. The physical source and sink correspond to Supply and Demand resources, respectively, and are only used to provide scheduling priority to TOR and ETC Self-Schedules in the IFM. The physical source is also used to provide scheduling priority to TOR and ETC in the RTM if appropriate pursuant to the TRTC Instructions.

Inter-SC Trades of Energy are paid (for trade in) or charged (for trade out) the relevant Trading Hub, LAP, or Generating Resource LMP.

Obligation CRRs from a source to a sink are paid the algebraic difference between the MCC components at the sink and the source. These payments are debited to the CRR Balancing Account.

CRR Options convey entitlement to Congestion revenues but not obligation to pay for counter flows. They allow the holder to avoid the obligation to pay when the Congestion component at the source is higher than the Congestion component at the sink. Thus, the CRR Option never has a negative value, but may have a positive value or a zero value. CAISO allocates CRR Options only to qualified entities that build new transmission facilities and do not receive a regulated rate of return – that is, merchant transmission developers who do not have a Transmission Revenue Requirement.

Finally, un-recovered Start-Up and Minimum Load Costs for non-self-committed resources are conditionally recovered through the Bid Cost Recovery mechanism. Moreover, unrecovered Energy and Ancillary Services Bid Costs for all resources are also recovered through the Bid Cost Recovery mechanism.

Details are given in the *BPM for Congestion Revenue Rights* and the *BPM for Settlements & Billing*.

6.7   Residual Unit Commitment

As described above, the IFM clears the market based on the Self-Schedules and Economic Demand Bids of the SCs, and as a result it may clear at an overall level that is significantly lower than the CAISO Forecast of CAISO Demand for the next day. The purpose of the RUC process is to assess the resulting gap between the IFM Scheduled Load and the CAISO Forecast of CAISO Demand, and to ensure that sufficient capacity is committed or otherwise be available for Dispatch in Real-Time in order to meet the Demand Forecast for each Trading Hour of the Trading Day.

To achieve this objective, the RUC process may commit and issue Start-Up Instructions to resources that are not committed at all in the IFM, as well as identify additional unloaded capacity from resources that are committed and scheduled in the IFM and designate this capacity as needed for Real-Time Dispatch in particular Trading Hours of the Trading Day.

While RUC only procures capacity for the 24 hours of the next day, RUC's time horizon is configurable from 24 hours up to 168 hours, unlike the 24 hour time horizon in IFM. This longer time horizon allows RUC to consider capacity needs in beyond the first day, which enables RUC to procure capacity in a manner that may reduce unit cycling over the midnight hours. For example, if RUC needs additional capacity near the end of the trading day RUC may procure

that capacity from a Long Start Unit if it foresees a need for that unit in the following day, and it would be more economic to keep the unit on-line than start it up the following day. In addition, the longer time horizon will allows the RUC process to consider the economic commitment of Extremely Long-Start Resources which have a startup time of greater than 18 hours and which generally cannot be considered in the normal IFM function. For these resources RUC may issue advisory start-up instructions for commitments which occur beyond the first 24 hours if the unit's start-up time would prevent the commitment to be feasible in a subsequent run. These advisory ELS commitment instructions are confirmed and made binding by the CAISO operators in the ELS commitment process. Within the RUC's time horizon, resource's commitment cost and bids will be considered in the entire corresponding time frame.

The ability to look beyond the twenty-four hour time period may be deactivated in order to address system and processing requirements. In which case, RUC will not issue any advisory commitments to ELS Resources and all ELS resources are committed by the CAISO operator through its processes, as necessary.

To perform this function, the RUC utilizes the same SCUC optimization and FNM that the IFM uses, but instead of using Demand Bids, it distributes the CAISO Forecast of CAISO Demand (here after CFCD) over the CNodes of the FNM using the system Load Distribution Factors (LDFs). It then treats all IFM resource (Generation, import and export) Schedules at a high scheduling priority so they are not re-optimized in RUC unless uneconomic adjustments are necessary. The RUC determines any incremental unit commitments and procures capacity from RUC Availability Bids to meet the RUC procurement target. Capacity selected in this process is then expected to be bid in and be made available to the RTM.

In performing this optimization, RUC ignores submitted Energy Bids and uses RUC Availability Bids instead, with the provision that such Bids must be zero for all capacity that has been designated Resource Adequacy Capacity. RUC also considers Start-Up and Minimum Load Costs for optimal commitment of units to meet the RUC procurement target for resources not committed in the IFM. Based on these Bids the RUC process calculates, in addition to the new Unit Commitment and dispatch process, RUC prices at each PNode. The RUC process thus designates RUC Capacity on a locational basis, in the sense that it identifies such capacity by determining a feasible Dispatch of that capacity to meet the RUC procurement target. The following summarizes the RUC processes described in this section:

➢ RUC Objective
➢ RUC Inputs
➢ RUC procurement target
➢ Distribution of CFCD on Full Network Model
➢ Day-Ahead Schedules for Supply

➢ RUC Availability Bids
➢ RUC Operational Constraints
➢ RUC Execution
➢ RUC Outputs

6.7.1   RUC Objective

The objective of the RUC optimization is to minimize the incremental Start-Up, Minimum Load and incremental RUC Availability Bids in order to ensure sufficient resources are committed and/or capacity is available to meet the adjusted CFCD for each hour over 24 hours of the next Operating Day, where:

➢ Incremental availability costs are represented by the RUC Availability Bids. RUC Availability Bids associated with capacity from resources that are under a contractual obligation to offer capacity such as Resource Adequacy Capacity resources are $0/MWh. RUC Availability Payments are paid to capacity eligible to receive such payments, per hour per MW of capacity identified in RUC above the greater of the resource's Day-Ahead Schedule, Day-Ahead RMR Schedule, RUC RA obligation or a resource's Minimum Load. RUC Availability Bids are processed as follows:

  ➢ For the first 24 hours of the optimization, RUC uses Availability Bids which are applicable for the Trade Date.

  ➢ For the forward trading days beyond the first trade day, for non-extremely Long- Start resources, the CAISO will selects a date from the historic seven days, up to and including the Trade Date, based on which date most closely matches the period. Energy bids and energy self schedules will be selected from that date and applied to the second 24 hour period.

  ➢ However, Energy Bids for ELS resources are copied from the Trade Date to the forward trade days, in order to preserve the bidding intention of the ELS resources.

➢ For the first 24 hours of the optimization, Day-Ahead Schedules and Ancillary Service Awards as a result of the IFM are maintained in determining the incremental quantity of RUC Capacity necessary to meet the adjusted CFCD.

➢ For the second and third 24 hours of the optimization, self-schedules from the selected dates are used as a proxy for the Day-Ahead schedules. Also for the second and third 24 hours, an adjustment is made to the CFCD to account for Ancillary Service awards that would have been made in the second and third 24 hour periods.

6.7.2   RUC Inputs

This section identifies those inputs that are particularly specific to RUC. Inputs that are common to all the DAM functions are identified in earlier sections of this BPM.

6.7.2.1   RUC Inputs Common to MPM/IFM

➢ System Load Distribution Factors, same as in MPM, (see Section 3.1.4, Load Distribution Factors)

➢ Generation Distribution Factors (see Section 3.1.2, Generation Distribution Factors)

➢ Transmission Constraints

➢ Generation Outages (see *BPM for Outage Management*)

➢ Daily total Energy Limits (applies to both Minimum Load and RUC Capacity)

6.7.2.2   Differences between first 24 hours and forward trade hours of the optimization

RUC data inputs for the 72 hour time horizon come from the following sources:

- Bids: As a proxy for the actual bids submitted for the Trade Date (first 24 hour period) bids, including RUC Availability Bids, Start-up Costs, and Minimum Load Costs, will be replicated from one of the last seven days, up to and including the Trade Date. The actual dates are chosen by the CAISO based on the closest match to the optimization period.

  In order to preserve the bidding intention of Extremely Long-Start Resources, energy bids and self-schedules for the second and third 24 hour period for these resources will be replicated from the Trade Date. If this were not done, it would be possible that an Extremely Long-Start Resource would receive a binding commitment based on a bid from a prior day, when they did not submit a bid for the Trade Date.

- Master File Data: Data including Pmin, Pmax, resource type, etc. will be replicated from the Trade Date to the forward hours. All resources will assume the MF definitions effective on the first trade day.

- Forecasts: Forecast data, including load forecasts, outage forecasts, etc. will be based on the latest data available.

6.7.2.3   RUC Zones

A RUC Zone is a designated area representing a collection of CNodes such as an IOU service area, UDC, MSS, Local Capacity Area. The CAISO may develop such collections of CNodes as sufficient historical CAISO Demand and relevant weather data becomes available to perform a Demand Forecast. RUC Zones are defined to allow CAISO Operators to adjust the CFCD on a local area basis as input to the RUC process, to ensure that the RUC process results in adequate local capacity procurement. The CFCD for a RUC Zone is produced by the CAISO's Demand Forecasting tools and is adjustable by CAISO Operators on a RUC zone basis.

The CAISO has defined the RUC Zones to be equivalent to the existing appropriate aggregation level of CAISO demand forecast systems. The mapping of RUC Zones to CNodes shall be static data, maintained in the CAISO Master File. The status of each RUC Zone shall remain active for as long as the CAISO's Automated Demand Forecast System (ALFS), or its successor, maintains such regional forecasting capabilities.

The CAISO will initially use three RUC Zones corresponding to three TAC areas. The number of RUC Zones may increase in the future in order to adjust the CFCD on a more granular basis. In the future, if the CAISO improves its demand forecasting capabilities to represent greater locational diversity, then the definitions of RUC Zones may be modified to reflect these changes. Such changes would be put before Market Participants for review and comment prior to implementation.

6.7.2.4   CAISO Forecast of CAISO Demand (CFCD)

CFCD is determined by CAISO for each load forecast zone. A load forecast zone corresponds to defined areas representing UDC, MSS or Load serving boundary for which CAISO has sufficient historical CAISO Demand and relevant weather data to perform a Demand Forecast.

CAISO forecasts CAISO Demand for each hour of the next seven Operating Days for each load forecast zone utilizing neural-network forecasting software that is widely used in the utility industry. To forecast the weather, CAISO utilizes multiple weather forecasting data sources so as to reduce forecasting errors. CAISO continually monitors its weather forecasting and Load forecasting results to ensure the average forecast error is minimized.

6.7.2.5   RUC Procurement Target

The RUC procurement target is based on the difference between CFCD and the IFM Scheduled Demand for each Trading Hour of the next Trading Day, and based on the CFCD for the following forward trade days.

The CFCD for each RUC Zone is distributed nodally over the Full Network Model (FNM). For the RUC process, the Day-Ahead Schedules for Supply resulting from the IFM (Self-Schedules for the following forward trade days) are modeled as Self-Schedules with high scheduling priority so that RUC identifies the incremental Supply needed to serve the difference between the Day-Ahead Schedule for Supply of Energy and the adjusted CFCD.

Once the initial RUC procurement target is calculated for each RUC zone, adjustments to these quantities may be made, on a RUC zone basis, according to the provisions described in the following sections. An example of such adjustment is Demand Response where if a SC informs CAISO about participation in Demand Response, CFCD is lowered accordingly which in effect reduces the RUC procurement target.

6.7.2.5.1 RUC Zone Adjustment

In order to ensure sufficient capacity and resources are committed while at the same time reducing the possibility of over-procurement in RUC, CAISO may make the following adjustments to the hourly CFCD by RUC zone. After all the individual adjustments are determined as described below the CAISO adjusts the CFCD of each affected RUC zone, without making changes to the LDFs within that RUC Zone. The RUC Zone CFCD adjustment can be absolute or relative as follows:

$$CFCD_{RZ,hour,adj} = CFCD_{RZ,hour,orig} + \Delta CFCD_{RZ,hour,adj}$$

Or

$$CFCD_{RZ,hour,adj} = CFCD_{RZ,hour,orig} \times \%CFCD_{RZ,hour,adj} / 100$$

Where:

- $\Delta CFCD_{RZ,hour,adj}$: The total quantity of CFCD adjustments in MW is based on the summation of the adjustment for: 1) Metered Subsystems that have opted-out or are Load Following MSS, 2) negative adjustments for Demand Response, 3) positive adjustments to CFCD for Eligible Intermittent Resources, 4) positive Demand adjustments to CFCD for forecasted net reductions in Self-Scheduled Supply (forecast reductions in Self-Scheduled Generation and imports) expected to be submitted in the Real-Time Market, and 5) any other CAISO Operator input. Criteria 1 through 4 describe the primary conditions under which the CAISO may change RUC procurement. However, as Balancing Authority Area Operator, the CAISO reserves the flexibility to adjust RUC procurement to address unforeseen circumstances that could affect reliability.

- $CFCD_{RZ,hour,orig}$: The original CFCD.

➢ *CFCD$_{RZ,hour,adj}$*: The adjusted CFCD used as the input for the RUC.

➢ *%CFCD$_{RZ,hour,adj}$*: The adjustment as a percentage of the original CFCD.

The adjustments associated with Eligible Intermittent Resources and forecasted Self-Schedules to be submitted in the Real-Time Market can result in either positive Demand side adjustments or positive Supply side adjustments. Positive Demand side adjustments are reflected as adjustment to the CFCD and positive Supply side adjustments are represented as an adjustment to the expected output of individual resources or imports. Refer to CAISO Tariff Section 31.5.3.

6.7.2.5.2   MSS Adjustment

This section is based on CAISO Tariff Section 31.5.2, Metered Subsystem RUC Obligation.

MSS Operators are permitted to make an annual election to opt-in or opt-out of RUC participation. Prior to the deadline for the annual CRR Allocation and Auction process, as specified in Section 36 of the CAISO Tariff, an MSS Operator must notify CAISO of its RUC participation option for the following CRR cycle:

CAISO Tariff Section 31.5.2.1, MSS Operator Opts-In to RUC Procurement states that:

➢ **Opt-in to RUC Procurement** – If the MSS Operator opts-in to the RUC procurement process, the SC for the MSS is treated like any other SC that Bids in the DAM with respect to RUC procurement by CAISO and allocation of RUC costs. CAISO considers the CAISO Demand Forecast of the MSS Demand in setting the RUC procurement target, and the SC for the MSS is responsible for any applicable allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8 of the CAISO Tariff.

CAISO Tariff Section 31.5.2.2, MSS Operator Opts-Out of RUC Procurement states that:

➢ **Opt-out of RUC Procurement** – If an MSS Operator opts-out of the RUC procurement process, CAISO does not consider the CAISO Demand Forecast of the MSS Demand in setting the RUC procurement target, and does not commit resources in RUC to serve the MSS Demand. The MSS Operator is responsible for meeting the Supply requirements for serving its Demand (i.e., "Load following") in accordance with this Section 31.5.2.2 of the CAISO Tariff, and it is exempt from the allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8 of the CAISO Tariff. The MSS that opts out of CAISO's RUC procurement has two options for meeting the Supply

requirements for serving its Demand, which it can select on an hourly basis depending on how it Self-Schedules its Demand in the DAM. The two options are:

- Based on CAISO Demand Forecast (see CAISO Tariff Section 31.5.2.2.1)
- Not Based on CAISO Demand Forecast (see CAISO Tariff Section 31.5.2.2)

An MSS that has elected to opt-out of RUC, or has elected to Load follow and therefore has also elected to opt-out of RUC, is required to provide sufficient resources in the Day-Ahead Market, and in the case of a Load following MSS, follow its Load within a tolerance band. To reflect these options CAISO replaces the CFCD for such an MSS with the quantity of Demand Self-Scheduled by the MSS in the IFM. By doing so, CAISO prevents RUC from committing additional capacity or resources for any differences between the CFCD for the MSS and the MSS Self-Scheduled quantities in the IFM. MSS adjustment is defined as follows:

$$CFCD_{MSS,Opt\text{-}out,RUC} = DS_{MSS\_Opt\text{-}out,IFM}$$

Where:

- ➢ $CFCD_{MSS,Opt\text{-}out,RUC}$: The CFCD used for the RUC zone for an MSS that either elected to opt out of RUC or has opted out as a result of electing to Load follow its MSS Demand.

- ➢ $DS_{MSS\_Opt\text{-}out,IFM}$: The quantity of scheduled CAISO Demand associated with an MSS that either elected to opt out of RUC or has opted out as a result of electing to Load follow its MSS Demand.

6.7.2.5.3   Demand Response Adjustment

There are two different categories of Demand Response: 1) Demand Response that is triggered by a staged emergency event and 2) Demand Response that is triggered by price or some other event that is known in advance. Only the Demand Response that is in category 2, that is certain of being curtailed, can be counted on as an adjustment to the RUC procurement target.   If an SC informs CAISO prior to 1000 hours on the day prior to the Trading Day that Demand Response for the Trading Day can be exercised by CAISO, then the CFCD is reduced accordingly when running RUC. This communication may happen in the form of a data template (for e.g. .csv file) which includes SCID, Trade Date, Hour, RUC Zone and the available Demand Response for the applicable time period in MW.

6.7.2.5.4   Eligible Intermittent Resource Adjustment

Eligible Intermittent Resources (EIRs) have the opportunity to bid or schedule in the Day-Ahead Market. Consequently, the ultimate quantity scheduled from EIRs may differ from the CAISO forecasted deliveries from the EIRs. CAISO may adjust the forecasted Demand either up or down for such differences by RUC zone for which the EIR resides. To the extent the scheduled

quantity for an EIR in IFM is less than the quantity forecasted by CAISO, the CAISO makes a Supply side adjustment in RUC by using the CAISO forecasted quantity for the EIR as the expected delivered quantity. However, to the extent the scheduled quantity for an EIR in IFM is greater than the quantity forecasted by CAISO, CAISO makes a Demand side adjustment to the RUC zone Demand equal to the difference between the Day-Ahead Schedule and the CAISO forecasted quantity.

CAISO uses a neural-network forecasting service/software to forecast deliveries from EIRs based on the relevant forecasted weather parameters that affect the applicable EIR. CAISO monitors and tunes forecasting parameters on an ongoing basis to reduce intermittent forecasting error. EIR adjustment is defined as follows:

$$CFCD_{RZ,IRPAdj} = \max(0, \Sigma G_{RZ,IRP,IFM,Sch} - \Sigma G_{RZ,IRP,DAM,CAISOForecast})$$

Or

$$SA_{Gen,IRPAdj} = \max(0, \Sigma G_{RZ,IRP,DAM,CAISOForecast} - \Sigma G_{RZ,IRP,IFM,Sch})$$

*W*here:

➢ $CFCD_{RZ,IRPAdj}$: The quantity of adjusted CFCD by RUC zone as a result of differences in scheduled and forecasted quantities for EIR for Trading Hour.

➢ $SA_{Gen,IRPAdj}$: The quantity of Supply adjustment made to an intermittent resource when the Day-Ahead Schedule for the EIR is less than the CAISO forecast for delivery for the EIR.

➢ $\Sigma G_{RZ,IRP,IFM,Sch}$: The total quantity of scheduled EIR within RUC zone for a Trading Hour.

➢ $\Sigma G_{RZ,IRP,DAM,CAISOForecast}$: The total quantity of CAISO forecast EIR deliveries within RUC zone for a Trading Hour.

6.7.2.5.5 Real-Time Expected Incremental Supply Self-Schedule Adjustment

In order to avoid over procurement of RUC, CAISO estimates the RTM Self-Schedules for resources that usually submit RTM Self-Schedules that are greater than their Day-Ahead Schedules. The estimation is performed using a similar-day approach.

The CAISO Operator can set the length of the Self-Schedule moving average window. Initially this moving average window is set by default to seven days; in which case the weekday estimate is based on the average of five most recent weekdays and the weekend estimate is based on the average of the two most recent weekend days. To the extent weather conditions differ significantly from the historical days, additional adjustment may be necessary, where the

systematic approach does not yield Schedules consistent with expected weather or other system conditions. After determining the estimate of Real-Time Self-Schedules, CAISO adjusts the CFCD of a RUC zone based on the forecasted quantity changes in Supply as a result of Self-Schedules submitted in RTM. A similar day forecasting approach is used to forecast the Real-Time Self-Scheduled adjustment. This adjustment for forecasted Real-Time Self-Schedules could result in positive or negative adjustments.

> A **Demand** adjustment to CFCD occurs when there is a net forecast **decrease** in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply.

> A **Supply** adjustment to the individual resources occurs when there is a net forecast **increase** in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply of the individual resource

6.7.2.5.6   Day-Ahead Ancillary Service Procurement Deficiency Adjustment

While CAISO intends to procure 100% of its forecasted Ancillary Service reserve requirement in the IFM based on the CFCD, CAISO reserves the ability to make adjustments to the CFCD used in RUC to ensure sufficient capacity is available or resources committed in cases that CAISO is unable to procure 100% of its forecasted reserve requirement in the IFM. While the CFCD used in RUC may be adjusted based on reserve procurement deficiencies, CAISO does not procure specific AS products in RUC, nor does the RUC optimization consider AS-related performance requirements of available capacity.

For example, it is not within RUC's objective to ensure that sufficient 10-minute service is available. However, to the extent RUC identifies capacity, such capacity is obligated to bid that capacity into the Real-Time Market as Energy and in so doing also allows CAISO to either dispatch Energy or acquire Operating Reserve from such capacity in the Real-Time Market to the extent such units qualify for the provision of such reserves.

6.7.2.5.7   Operator Review & Adjustment

The CAISO Operator reviews the CFCD and all calculated adjustments. The CAISO Operator has the authority to accept, modify, or reject such adjustments. If the CAISO Operator determines it must modify or reject adjustments, the CAISO Operator logs sufficient information as to reason, Operating Hour, and specific modification(s) made to the calculated adjustments. Furthermore, such CAISO Operator adjustments are reviewed and approved by the CAISO Shift-Supervisor.

CAISO makes information regarding CAISO Operator adjustments available to Market Participants in a report. This information is described in more detail in the *BPM for Market Instruments, Sections 11 and 13.*

6.7.2.6 Day-Ahead Schedules for Supply

Prior to determining the quantity of additional capacity that needs to be available, CAISO introduces and honors the resource commitments and associated Supply Schedules that have cleared the IFM. However, after potential RUC zone specific procurement target adjustments are factored into CFCD, the resulting distribution of Demand on individual CNodes for RUC may be different from that used in the IFM. Because of this, RUC Capacity may be procured from resources in a RUC zone where the CFCD had been increased relative to the IFM scheduled Demand, even when the total system wide Day-Ahead Schedules are equal to or greater than the total system wide RUC CFCD. As a result of this, IFM resource Schedules entered into the RUC optimization as high priority Self-Schedules (essentially fixed resources) may need to be reduced. For some resources, this may result in a RUC Schedule that is lower than the Day-Ahead Schedule in order to satisfy the SCUC power balance constraint, which effectively means that the Day-Ahead Schedule of the resource was reduced to accommodate procurement of RUC Capacity from another resource. Note that this reduction of the Day-Ahead Schedule in RUC has no bearing on the settlement of the original Day-Ahead Schedule.

RMR Generation Schedules that have been determined in the pre-IFM, MPM process are also honored in the RUC process. Therefore, if an RMR resource dispatched to 200 MW in the pre-IFM, MPM process, but only clears the IFM at 100 MW, the RMR resource is scheduled at 200 MW as input to RUC.

Constrained Output Generators (COG) are dispatched to their constrained output level in RUC. Therefore, a COG resource that has a PMin=PMax=50 MW may be dispatched in IFM at 20 MW. In RUC, however, such a COG resource schedule of 50 MW is enforced as input to the RUC process.

Intertie transactions with neighboring Balancing Authorities must be based on physical schedules. Since Virtual Supply and Virtual Demand are not considered in RUC, the RUC intertie results are used as a basis for energy schedules subject to check-out. Note that RUC attempts to honor the cleared IFM physical schedules like the Supply Schedules mentioned above. In the case of intertie schedules, Intertie constraints may bind in cases where the counter-flow effects of Virtual Bids are removed, thus the cleared physical Intertie results from RUC may not be the same as the results from IFM. The difference from the treatment of Supply Schedules is that the RUC result is operationally binding and becomes the basis for ~~e-Tag~~E-

Tags that may be submitted in the Day Ahead timeframe. In other words, energy profiles on e-TagE-Tags submitted for IFM awards above cleared RUC schedules will not be approved.

Other supply, such as Existing Transmission Contracts (ETCs), Converted Rights (CVRs) or Transmission Ownership Rights (TORs) Self-Schedules are also honored at the Self-Scheduled levels established in the Day-Ahead Schedule through the IFM.

Wheeling transactions are not explicitly kept balanced in RUC because they are already protected by IFM self-schedule scheduling priority.

Forbidden Region constraint is not enforced in RUC because the RUC is procuring capacity not energy. This constraint is enforced in MPM/IFM.

Supply adjustments to Eligible Intermittent Resources and forecasted increased in RTM Self-Schedules may be made as described in Section 6.7.2.5.16.7.2.5.16.7.2.5.1, RUC Zone Adjustment.

6.7.2.7   RUC Availability Bids

Participation in RUC is validated by the RUC eligibility designation contained in the Master File. Generating Units (except for certain exempt Use Limited Resources), Dynamic System Resources and Resource-Specific System Resources are designated as eligible for RUC. Non-Resource-Specific, non-Dynamic System Resources and RDRR resources are designated as NOT eligible for RUC. SCs may only submit RUC Availability Bids (above the Minimum Load) for which they show also submit an Energy Bid to participate in the IFM. Scheduling Coordinators may submit RUC Availability Bids on behalf of eligible capacity that is not subject to a RUC obligation. The CAISO will optimize all RA Capacity from Generating Units, Imports or System Resources at $0/MW per hour for the full amount of RA Capacity for a given resource. SCs may submit non-zero RUC Availability Bids for the portion of a resource's capacity that is not RA Capacity, unless the resource is subject to CAISO Tariff Appendix II, in which case the RUC Availability Bids must be $0/MWh for any capacity bid in.

A RUC Availability Bid is a ($/MW, MW) pair. The meaning of a RUC Availability Bid differs depending on whether the resource that submits the RUC Availability Bid has a Resource Adequacy obligation. If a resource does not have a RA obligation, the Scheduling Coordinator has the option of submitting a RUC Availability Bid pursuant to the rules in Section 30.5.2.7 of the CAISO tariff and Section 7.1 of the BPM for Market Instruments. If a resource has a RA obligation, a certain amount of capacity of this resource is registered with CAISO as RA Capacity. RA Capacity that is not a hydroelectric Generating Unit, Pumping Load or Non-

Dispatchable Use-Limited Resource exempt from the RUC obligation pursuant to CAISO Tariff section 40.6.4.3.2, must also participate in both the IFM and the RUC processes. Moreover, the RA Capacity must participate in the RUC process with a $0/MW RUC Availability Bid for the entire RA Capacity. This $0/MW RUC Availability Bid is generated by the CAISO on behalf of resources with a RUC obligation.

An SC need not submit a RUC Availability Bid for a Generating Unit or System Resource for the portion of the resource capacity that is under RUC obligation. For these resources that are obligated to offer their RA Capacity to RUC pursuant to Section 40.6 of the Tariff, RUC will automatically insert a RUC Availability Bid for the applicable RA Capacity and that bid will be equal to $0/MWh. In the event that a Generating Unit or System Resource only has part of its capacity designated as RA Capacity, the SC may only submit a RUC Availability Bid for any non-RA Capacity for that resource. The RUC Availability bid used in RUC will be constructed as follows: from the higher of the Minimum Load or the IFM Schedule up to the RA Capacity minus any Regulation Up/ Spin/ Non-Spin awards, a $0/MWh bid is created for any unused portion of the resource's RA Capacity. Any submitted RUC Availability Bid is then put on top at the submitted price. For Use-Limited Resources that are not exempt from the RUC obligation, the ISO will create a RUC Availability Bid consistent with the resources' RA capacity offered into the Day-Ahead Market through their Bids.

As stated in CAISO Tariff Section 40.6.4.3.2 "Hydro and Non-Dispatchable Use Limited Resources", Hydro resources and Non-Dispatchable Use-Limited Resources are required to submit Self-Schedule or Bids in the Day-Ahead Market for their expected available Energy or their expected as-available Energy, as applicable, in the Day-Ahead Market and RTM. Hydro resources and Non-Dispatchable Use-Limited Resources are not subject to commitment in the RUC process.

The RUC bidding requirements applicable to RA Capacity are described in more detail in the BPM for Reliability Requirements.

The total amount of RUC Capacity (which considers both the RA Capacity plus the submitted RUC Availability Bid quantity for an RA resource) is limited by the upper operating limit minus the sum of Day-Ahead Schedule and the upward Ancillary Service Awards. In other words, the sum of the DAM Energy Schedule, the upward Ancillary Service Awards including Ancillary self-provisions, and the RUC Award is limited by the upper operating limit.

If a resource is determined to have an RMR requirement for an hour in the Day-Ahead, and if any portion of the RMR requirement has not been cleared in the IFM by the Scheduled

Demand, the entire amount of RMR requirement are represented as a RMR Self-Schedule in the RUC to avoid over-committing other resources.

While IFM honors multi-hour Intertie Block Bids when procuring Energy, post IFM processes (RUC and RTM) are not designed to enforce multi-hour block constraints. Therefore, RUC evaluates all intertie RUC Availability and RTM evaluates System Resource Energy Bids on an hourly basis instead of a multi-hour block basis.

Exhibit 6-4 defines the RUC Capacity that is available on a Generator that has been scheduled by the IFM. This Generator is also providing AS.

Exhibit 6-5: Capacity Available for RUC
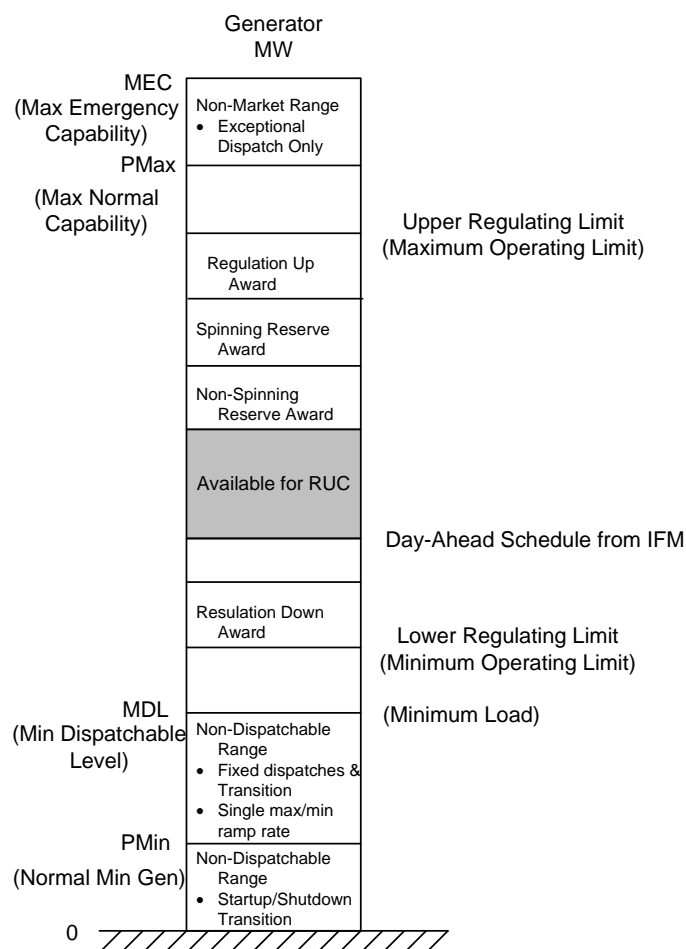
Exhibit 6-5 summarizes the characteristics of: Start-Up Costs, Minimum Load Costs as they apply in RUC, and the RUC Availability Bid for the various types of resources.

Exhibit 6-6: RUC Start Up, Minimum Load, & Availability Bid Eligibility

	Start-Up Costs	Minimum Load Costs	RUC Availability Bid
Participating Generator	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	RA Capacity = $0 Non RA Capacity is eligible to Bid (CAISO Tariff: 31.5.1.1, 31.5.1.2)
Constrained Output Generator (COG)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.2)	No RUC Availability Bid permissible; but accounted for in RUC based on Minimum Load cost bid (CAISO Tariff: 31.5.1.1)
Resource-Specific System Resource	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.4)	Cost-Based Or Standing six-month Bid (CAISO Tariff: 30.4, 30.5.2.4)	RA Capacity = $0 Dynamic non-RA Capacity eligible to bid otherwise Other non-RA not eligible to bid into RUC (CAISO Tariff: 31.5.1.1)
Non-Resource-Specific System Resource	N/A (CAISO Tariff: 30.5.2.4)	N/A (CAISO Tariff: 30.5.2.4)	RA Capacity = $0 Dynamic non-RA Capacity eligible to bid otherwise Other non-RA not eligible to bid into RUC (CAISO Tariff: 31.5.1.1)
Participating Load (using Full Participating Load Model)	Not supported initially	Not supported initially	Not supported Initially
Participating (Pump) Load (using pumped-storage model)	N/A	N/A	N/A
Non-Participating Load	N/A	N/A	N/A

6.7.2.8   RUC Operational Constraints

The RUC process has the ability to incorporate additional operational constraints using solution parameters that are set by a CAISO Operator. The following sections describe the criteria that are used for setting these constraint parameters. Although the CAISO Operator can set these constraint parameters, these parameters are not expected to change often after a period of initial implementation. After the initial implementation period, CAISO will post a notice to Market Participants when these parameters are to be changed.

6.7.2.8.1   Capacity Constraints

The capacity constraints ensure that sufficient RUC Capacity is procured to meet the CFCD. This is accomplished by enforcing the Power balance between the total Supply (which includes IFM Energy Schedules, RMR Generation Schedules that result from MPM and RUC Capacity) and the total Demand (which includes IFM export Schedules and Demand Forecast.) The CFCD can be adjusted to increase the RUC target if there is AS Bid insufficiency in IFM, as described in Section 6.7.2.46.7.2.46.7.2.4 above.

6.7.2.8.2   Maximum Energy Constraint

In order to reduce the possibility that CAISO over-commits capacity in RUC when trying to meet the CFCD, RUC is capable of enforcing a constraint on the solution that would limit the total quantity of IFM Energy Schedules plus RUC Minimum Load Energy to be less than a percentage of the total CFCD.

$$\Sigma(\text{Pmin}) + \Sigma(\text{DA Imports}) - \Sigma(\text{DA Exports}) + \Sigma(\text{DA Gen}) <= \%E_{RUC,Limiit} \times CFCD$$

Where:

> $\Sigma(\text{PMin})$: The total of all Minimum Load Energy committed in RUC for a Trading Hour
> $\Sigma(\text{DA Imports})$: The total of DA Scheduled imports for a Trading Hour
> $\Sigma(\text{DA Exports})$: The total of DA Scheduled exports for a Trading Hour
> $\Sigma(\text{DA Gen})$: The total of DA Scheduled Generation Energy for a Trading Hour
> $\%E_{RUC,Limiit}$: The % Energy of CFCD Energy limitation.

This RUC Energy constraint is a soft-constraint and can be violated to obtain a solution. CAISO currently sets the RUC Energy Limit constraint to be between 95% and 100% of the CFCD.

Operational factors that are considered in setting this parameter are:

> Demand Forecast error
> Operational conditions such as Overgeneration

➢ Seasonal factors

6.7.2.8.3   Short-Start Unit Capacity Constraint

This section is based on CAISO Tariff Section 31.5.4, RUC Procurement Constraints

In order to limit RUC from relying excessively on the capacity of Short-Start Units when making RUC decisions, CAISO may limit the percentage of total Short-Start Unit capacity that is committed in RUC. Short-Start Units are limited based on the following equation:

$$\sum(CAP_{RUC,QS}) <= \%SS \times \sum(CAP_{Total,QS})$$

Where:

➢ $\sum(CAP_{RUC,QS})$: The total capacity of Short-Start Unit capacity committed in RUC
➢ %SS : The percentage of total Short-Start Unit capacity parameter
➢ $\sum(CAP_{Total,QS})$: The total Short-Start Unit capacity available in the CAISO.

The Short-Start Unit capacity percentage limit is set to 100% by default. However, CAISO Operators may set this parameter as low as 75%. Operational factors that are considered in setting the Short-Start Unit constraint parameter are:

➢ Historical confidence that a Short-Start Unit actually starts when needed. Short-Start Unit performance is assessed based on operational experience among the CAISO's operators, collectively for all Short-Start resources.
➢ The need to conserve the number of run-hours and the number of start-ups per year for critical loading periods
➢ Seasonal constraints such as Overgeneration[28]

All of these factors work in the same direction to reduce the capacity percentage limit below the default value of 100%.

6.7.3   RUC Execution

After completing the IFM and steps described above, CAISO executes the RUC process for the next Trading Day using the Security Constrained Unit Commitment (SCUC) algorithm. RUC simultaneously optimizes between 24 and 168 hours with the objective to minimize the total Start-Up Costs, Minimum Load Costs, and incremental availability costs (i.e., RUC Availability Bid) while meeting the adjusted CFCD. Using the Full Network Model, RUC also ensures that transmission constraints are not violated.

---

[28] Over-generation tends to occur during off-peak hours, when the level of RUC procurement is low. This factor, therefore, should have only a small impact on Short Short-Start Unit procurement.

The RUC process is run every day whether or not the Day-Ahead Schedule for Demand is greater than the CFCD. If no additional resource needs to be procured or no additional resources need to be committed, then RUC completes its execution without having to commit any additional resource capacity. However, it is possible that RUC needs to identify additional RUC Capacity or commit additional resources either because of insufficient Load being scheduled in the IFM or due to transmission constraints because of differences in the Location and quantity of Demand scheduled in the IFM and the CFCD.

While RUC commits resource capacity from Long-Start and Short-Start Units to meet CFCD, RUC does not automatically de-commit resources in cases of Overgeneration conditions or in cases where the Day-Ahead Schedules exceed the CFCD. The RUC solution identifies to the CAISO Operator resources that may need to be considered for de-commitment. The CAISO Operator reviews and assesses the results prior to making any manual de-commitment decisions.

6.7.4   RUC Outputs

This section summarizes the results of the RUC process. Unless otherwise noted, only results from the first 24 hours are considered binding and published.

6.7.4.1   RUC Schedules

The total MW per hour amount of capacity committed by RUC including the MW per hour amounts committed in the Day-Ahead Schedule.

6.7.4.2   RUC Capacity and RUC Awards

RUC Capacity and RUC Awards are determined as follows:

➢ RUC Capacity is the positive difference between the RUC Schedule and the greater of the Day-Ahead Schedule or the Minimum Load of a resource.

➢ The portion of the capacity that corresponds to the Minimum Load is not considered RUC Capacity and it is not eligible for RUC Bid Cost compensation since the Minimum Load Energy is compensated at the Minimum Load Cost in Bid Cost Recovery. For Extremely Long-Start Resources committed in the following forward trade days of the time horizon, only capacity up to Minimum Load will be committed.

➢ The portion of the RUC Capacity from a RMR unit that is used in the RUC optimization to meet CFCD is not eligible for RUC Award since the capacity is already compensated through RMR Contract.

> The portion of the RUC Capacity that corresponds to RA RUC obligation is also not eligible for RUC Award.

> Any RUC Capacity in excess of RMR Capacity or RA RUC obligation is considered a RUC Award eligible for RUC Payment.

CAISO only issues start-up instructions to Long-Start Units and Extremely Long-Start Resources that must be started sufficiently in advance of real time to meet Real-Time Demand. For Extremely Long-Start Resources, advisory start-up instructions may be issued for start times up to the end of the time horizon. However, these instructions will only be binding after confirmed by the CAISO operator and if the resource's startup time prevents it's re-evaluation in the following day's IFM/RUC run. For other units, the CAISO re-evaluates their commitment decisions in STUC and RTUC. However, the RUC Schedule determined by RUC is made available to the relevant SCs even if a RUC Start-Up instruction is not issued in the DAM.

6.7.4.3   RUC Pricing

RUC Prices are calculated by the RUC optimization based on the RUC Availability Bids, as modified by CAISO's validation for Resource Adequacy requirements. A resource that receives a RUC instruction is compensated by the product of the RUC Award and the RUC Price of its Location. The determination of the RUC Price is similar to the determination of the Energy LMP; except that RUC Availability Bids are used for the RUC Price. The RUC Price has Energy, Loss, and Congestion components associated with it similar to LMPs that are produced in the IFM, however, the RUC Prices are not decomposed.

Note that OASIS reports RUC prices as RUC LMPs.

6.7.4.4   RUC Start-Up Instructions

RUC issues binding start-up instructions only to Long-Start Units. RUC also issues advisory start-up instructions for Extremely Long-Start Resources that are validated by the CAISO Operator through the Extremely Long- Start commitment process. For Short-Start Units, RUC evaluates the Start-Up Costs, but does not issue start-up instructions. For Short-Start Units, Start-Up Costs are eligible for Bid Cost Recovery only if the resource is actually started up as a result of a binding start-up instruction issued by RTUC.

Short-Start Units that are not under a contractual obligation to offer capacity (e.g., Resource Adequacy Capacity resources and Reliability Must Run resources that have been scheduled by an RMR Dispatch) are eligible to a RUC Award even though they are not issued a binding RUC Start-Up instruction in RUC.

If the CAISO does not issue a Start-Up instruction to such units in the Real-Time Market, such units are compensated for their RUC Award, but do not receive payment for RUC Start-Up Costs and Minimum Load Costs, as they were never started up. Short-Start Units that are under a contractual obligation to offer capacity are not eligible to RUC Availability Payments, but are compensated for Start-Up and Minimum Load Costs through Bid Cost Recovery if they receive a Start-Up instruction in the RTM and actually start up.

6.7.4.5   RUC Settlement

All RUC Awards are paid the RUC Price. RA and RMR units do not receive RUC Awards for their RA/RMR Capacity. The RUC cost allocation uses a two-tier Settlement approach.

> ➢ In the first tier, the Net RUC Bid Cost Uplift is allocated to positive Load deviations up to MW RUC Capacity per MW Load deviation basis.
> ➢ In the second tier, any remaining Net RUC Bid Cost Uplift is allocated pro rata to all Demand.

See the *BPM for Settlements & Billing* for details on Settlement. CAISO Tariff section 11.8.6.5 specifies the two allocation tiers for RUC.

6.7.4.6   RUC Intertie Schedules

RUC publishes cleared Intertie schedules, which will be used as a basis for tagging in advance of real-time.

6.8   Extremely Long-Start Commitment

Some Extremely Long-Start (ELS) Resources may need to receive Start-Up Instructions from CAISO before DAM results are available. According to the CAISO Tariff 27.4.1:

ELS Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day will be committed manually by the CAISO Operators. Such manual commitment instructions are determined in combination with other operational expectations and reliability needs.

Extremely Long-Start Resources may be either physical resources with Start-Up Times greater than 18 hours or the contractual intertie resources that must receive commitment instructions by 0600 hours one-day ahead. Therefore, there is a need for a manual procedure to determine the commitment status of such resources two days in advance. This procedure is called the Extremely Long-start Commitment (ELC) process.

The ELC process is performed after the regular DAM processes are completed. The ELC process consists of the following steps:

4) The ELC process is initiated by the CAISO Operator.

5) If available, the CAISO Operator evaluates the non-binding advisory commitment issued by the RUC process for ELS resources. If the solution is appropriate and consistent with good utility practice, the CAISO Operator will approve the commitment. Once approved, the RUC-generated commitments will be communicated to ELS resources using the same processes as for IFM and RUC commitment of non-ELS resources. See section 6.4.6 for more information.

   Otherwise, the CAISO operator will employ the following steps to commit ELS resources:

6) ELC process for Trading day 'T+2' occurs after the completion of the DAM for Trading day 'T +1'

7) The CAISO will consider resources for ELS decision if the resource has submitted a DAM Energy bid for Trading day 'T+1'. The CAISO Operator will evaluate all the ELS submitted bids to make a decision based on Start-up Cost, Minimum Load Cost, power flow studies and Good Utility Practice.

8) Once the decision is made, the selected Extremely Long-Start Resources will receive start up instruction for Trading day 'T+2' by 1500 hours of Trading day 'T'.

9) The CAISO Operator manually notifies (in the form of a phone call) the pre-committed ELS resources about their binding start up instructions as determined in the steps above.

10) The commitment instructions will not include schedules greater than the Minimum Load.

11) By 1000 hours of the Trading day 'T+1', pre-committed ELS units are required to submit the same bid (Bid submitted for Trading day 'T+1') to the CAISO for Trading day 'T+2'. This is because the original bid was used for determination of ELS commitment.

12) Depending on system conditions and resource characteristics CAISO may make decisions more that Trading day 'T+2' days ahead.

The Master File has an ELS Resource flag that indicates that the resource is subject to the ELC procedure.

Commitments of ELS Resources outside of this manual ELS commitment process must be made through Exceptional Dispatches.

7.   Real-Time Processes

Welcome to the *Real-Time Processes* section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- ➢ A description of the Real-Time Market timelines

- ➢ How CAISO performs the Hour-Ahead Scheduling Process (HASP)

- ➢ How CAISO performs the Short-Term Unit Commitment (STUC) process

- ➢ A description of the Real-Time Unit Commitment (RTUC) and Fifteen-Minute Market (FMM) processes

- ➢ A description of the Real-Time Economic Dispatch (RTED) process

- ➢ A description of the Real-Time Manual Dispatch (RTMD) process

- ➢ A description of the Real-Time Contingency Dispatch (RTCD) process

A timeline and data flow diagram for the Unit Commitment and Dispatch processes of the Real-Time Market is included.

7.1   Differences from IFM

In general, the RTM applications are multi-interval optimization functions minimizing the cost of dispatching Imbalance Energy and procuring additional AS, when applicable, subject to resource and network constraints. In this respect, the RTM applications are not much different than the IFM application. The main differences are the following:

- ➢ The IFM application uses hourly time intervals, whereas the RTM applications use sub-hourly time intervals within their Time Horizon.

➢ The Time Horizon of the IFM application spans the next Trading Day, whereas the Time Horizon of the RTM applications is variable (due to submission timelines limiting the availability of real-time bids beyond the end of the next hour) and spans the current and next few Trading Hours at most. The RTM applications run at periodic intervals, every 5 or 15 minutes, with a Time Horizon that ends at or beyond the Time Horizon of the previous run. Results for time intervals other than the second (binding) one in the Time Horizon are advisory since they are recalculated the next time the application runs.

➢ The IFM application uses Demand Bids to clear against Supply Bids, whereas the RTM applications use CAISO Forecast of CAISO Demand and final scheduled exports. Demand Bids and Virtual Bids are not accepted in the RTM.

➢ The RTM applications use the latest available information about resource availability and network status; in fact, the optimal Dispatch is initialized by the SE solution that is provided by the Energy Management System (EMS).

➢ The IFM application commits resources optimally for the next Trading Day using three-part Energy Bids. Almost all resources can be considered for optimal commitment, except for resources with extremely long Start-Up, because the full cost impact of commitment decisions for these resources cannot be evaluated within the IFM Time Horizon. Similarly, the RTM applications that have Unit Commitment capabilities can commit resources optimally within their Time Horizon, however, because that Time Horizon is short (a few hours at most), only Fast-Start, Short-Start and Medium Start Units can be committed. Consequently, any Long-Start Units that are not scheduled in the IFM or RUC, are effectively not participating in the RTM.

➢ Unlike the IFM application, the RTM applications need to interface with the Automated Dispatch System (ADS) to communicate financially binding commitment and Dispatch Instructions, and with the CAS for confirmation of System Resource Schedules and Dispatch.

➢ The RTM applications provide more control to the CAISO Operator with the capability to adjust the Imbalance Energy requirements (via adjustments to the Load forecast), block commitment or Dispatch Instructions, or issue Exceptional Dispatches. This CAISO Operator input is necessary to address any unexpected system conditions that may occur in Real-Time.

➢ The RTM applications also provide the functionality to the CAISO Operator to switch the system or individual resources into a Contingency state under which Contingency Only Operating Reserves are dispatched optimally to address system contingencies.

Contingency Only Operating Reserves are otherwise reserved and not dispatched by the RTM applications.

➢ The CAISO Operator may augment or supplant the Dispatch Instructions generated by the RTM application with Exceptional Dispatches if necessary to address system conditions that are beyond the modeling capability of the RTM applications.

➢ The ISO market systems will validate Bids at transmission paths with zero rated TTC in both directions. The details of this procedure are provided in the BPM for Market Instruments. For System Resources which have registered a primary and alternate tie path in the Master File, and were awarded schedules in IFM/RUC on the primary tie, and the primary tie is rated zero in both directions in the real-time, the real-time systems will consider the award to be on the alternate tie for dispatch purposes.

➢ Unlike the IFM application, RDRR resources will not be selected for normal dispatch unless the CAISO Controlled Grid is in one or more of the following conditions as provided in the associated operating procedures (see CAISO public website):

    ➢ For system emergencies, including

    ➢ Transmission emergencies; and

    ➢ Mitigating imminent or threatened operating reserve deficiencies

    ➢ For resolving local transmission and distribution system emergencies.

In the event these conditions exist, the CAISO operator may choose to activate a software flag which will allow these resources to be dispatched. Likewise, after the condition has ended and conditions have stabilized, the operator will reset the flag which will prevent the resources from being dispatched, other than to their day-ahead awarded value. Day-ahead awarded values should be followed in either case. RDRRs with day-ahead schedules will not receive any RT dispatches until operational conditions exist such that the software flag is activated per condition above. Once activated, the RT dispatch instructions generated will include both DA and RT MW components through ADS per section 7.2.3.5.

➢ RDRR resources have the option of discrete dispatch capability in the RTM application. Similar to a COG unit, the RDRR resource selecting the discrete dispatch option will be dispatched either to zero or to a specified MW quantity, and will be allowed to set the LMP if a portion of energy from the resource is needed to serve demand. Unlike a COG unit, the MW quantity is specified via the hourly Energy Bid.

➢ NGR electing to use Regulation Energy Management can only provide regulation. The ability to provide regulation is dependent on their real-time state of charge. Thus their SOC energy constraint is managed in the Real-Time Economic Dispatch application in combination with EMS only, not IFM or Real-Time Unit Commitment.

7.1.1   Real-Time Market Timelines

Exhibit 7-1 shows the relationship among the Unit Commitment processes. Each of these applications is described further on in this BPM:

➢ RTUC/FMM #1 – incorporates HASP, starting 67.5 minutes before the Trading Hour
➢ RTUC/FMM #2 – starting 52.5 minutes before the Trading Hour
➢ STUC –starting 52.5 minutes before the Trading Hour
➢ RTUC/FMM #3 – starting 37.5 minutes before the Trading Hour
➢ RTUC/FMM #4 – starting 22.5 minutes before the Trading Hour

The timeline for RTM is presented in Exhibit 7-1.The Real-Time Economic Dispatch has a rolling Time Horizon of up to 13 5-minute intervals, executing every 5-minutes at the middle of the 5-minute clock intervals.

Exhibit 7-1: HASP/STUC/RTUC Timelines
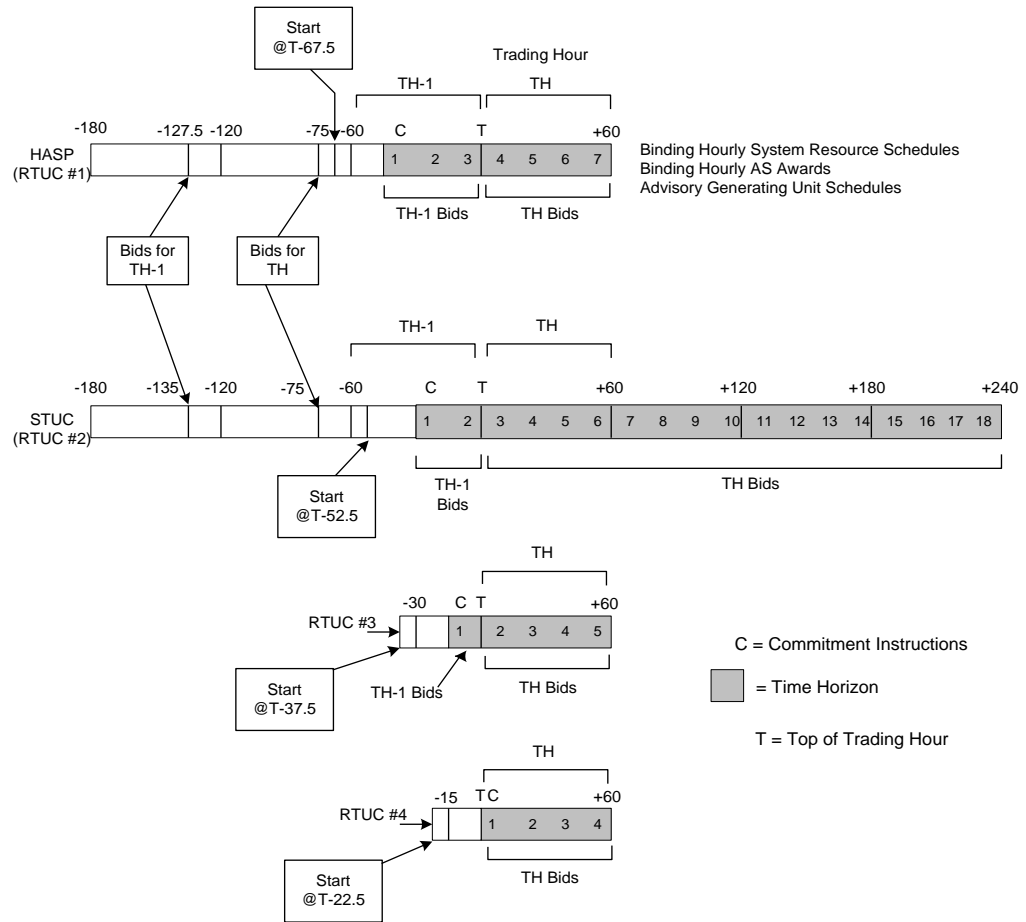
7.1.2   Real-Time Dispatch Principles

Generally, the objective of a Real-Time Market is system balancing and Load following on a forward looking basis above and beyond the normal function of the Automatic Generation Control (AGC). Since the RTM is forward-looking, AGC is mainly a control rather than an Energy service. As AGC units depart from their Dispatch Operating Point (DOP) responding to frequency and net interchange deviations, they temporarily supply or consume balancing Energy. The Real-Time Economic Dispatch function dispatches ahead of AGC, while AGC resolves shorter-term imbalances. Irrespective of the particular Dispatch methodology that is employed in a Real-Time Market, the schedule deviations can be classified into "instructed" and "uninstructed".

➢ Instructed deviations are the result of participating resources responding to Dispatch Instructions. Instructed deviations are usually price setters, whereas Uninstructed Deviations are Price Takers and may be subjected to penalties.

➢ Uninstructed Deviations may be the result of Load forecast errors, Forced Outages and contingencies, strategic behavior, modeling limitations, failure to follow Dispatch Instructions, etc. Uninstructed Deviations may prompt the response of AGC to balance the system creating Imbalance Energy requirements that are met through instructed deviations calculated optimally by the RTM.

7.1.3   Flexible Ramping Product

Flexible Ramping Product (FRP) is a market-based product, it was developed to address the operational challenges of maintaining power balance in the real-time dispatch. FRP is composed of Flexible Ramping Up (FRU) and Flexible Ramping Down (FRD) capacities. This product is only procured in the Real-Time Unit Commitment (RTUC), which includes the Fifteen Minute Market, and Real-Time Dispatch (RTD) market. The FRP is resource ramping capacity that is reserved from scheduling or dispatch in the current market to address uncertainty that may materialize in real time. The purpose of FRP is to insure against insufficient ramp capability in real time that may result in extreme prices.

7.1.3.1   Flexible Ramping Product Market Design

FRP is modeled as ramping capability constraints. Modeling flexible ramping in RTUC helps real-time unit commitment make the correct decisions in creating ramping headroom if it is

necessary. The real-time unit commitment decisions are binding if such decisions cannot be revisited in later runs due to physical commitment time constraints. The flexible ramping headroom and energy schedules in RTUC are financially binding at the FMM price. The ISO will also re-optimize the procurement of flexible ramping capability in RTD and awards will be compensated according to the marginal prices in RTD where the energy awards are also financially binding.

7.1.3.1.1   FRP Features

The following are the features of the FRP;

- There is no bidding of FRP and the ISO will not procure FRP in the day-ahead market.
- All resources can provide forecasted movement between market intervals in both the FMM and RTD.
- Only resources that have an economic bid and are dispatchable in RTD can have a flexible ramping award in excess of its forecasted movement.
- Flexible ramping awards over the forecasted movement between intervals is procured to meet uncertainty in the 5-minute net load forecast.
- The ISO does not certify flexible ramping capability as it does for ancillary services.
- The ISO will use the internal DOT to evaluate and award the FRP. For instance, if a variable energy resource is using its own 5-minute forecast for settlement of energy. Ramping capability on this resource will be based upon the ISO forecast of the resources. The ISO forecast, not the resource's forecast, is used to clear both FMM and RTD.
- The Flexible Ramp Up Price (FRUP) will be the Shadow Price of the upward Uncertainty Requirement constraint, which is the cost sensitivity of relaxing the upward Uncertainty Requirement constraint ($/MWh).
- The Flexible Ramp Down Price (FRDP) will be the Shadow Price of the downward Uncertainty Requirement constraint, which is the cost sensitivity of relaxing the downward Uncertainty Requirement constraint ($/MWh).
- Since there is no economic bidding, there is no self-provision of FRP or market power mitigation rules applied to flexible ramping awards.

7.1.3.1.2   Co-optimizing Flexible Ramping Products with Energy and Ancillary Services

The optimization model applies to both RTUC and RTD. RTUC and RTD both optimize over multi-interval horizons. FRP will be modeled by enforcing ramping constraints in each interval of RTUC and RTD. Modeling FRP in advisory intervals enables the optimization to foresee

potential problems and take actions accordingly. As is the case for energy dispatches, only the flexible ramping award in the first RTD interval is financially binding.

The objective function is modified to ensure sufficient ramping capability is maintained in order to meet both forecasted movement and uncertainty. The changes to the constraints involving flexible ramping are as follows.

Upward ramping capability limit: This constraint ensures that a resource's upward ramping award plus the total amount of upward reserves (regulation-up, spinning, and non-spinning) awards does not exceed its upward ramping capability over the market clearing interval.

Downward ramping capability limit: This constraint ensures that a resource's downward ramping award plus the regulation-down award does not exceed its downward ramping capability over the market clearing interval.

Active power maximum limit: This constraint limits the awards of energy schedule, upward reserves and upward FRP to be less than or equal to the resource's maximum operating capability.

Active power minimum limit: This constraint limits the energy schedule minus the awards of regulation-down and downward FRP to be greater than or equal to the resource's minimum operating level.

Upward flexible ramping requirement: This constraint ensures that the total amount of upward FRP awards at least meets the requirement.

Downward flexible ramping requirement: This constraint ensures that the total amount of downward FRP awards at least meets the requirement.

FRP is a 5-minute ramping capability based on the dispatch level and the resource's ramp rate. The RTUC and RTD have different market clearing interval granularity:

• RTUC has 15-minute market clearing interval, and

• RTD has 5-minute market clearing interval.

In the optimization, the ISO will model the average 5-minute ramping capability over the applicable market-clearing interval. The ramping capability over the market clearing interval will be converted to the average 5-minute ramping capability by dividing it by an averaging factor AF (AF = 3 for RTUC, and AF=1 for RTD). If resource A has 60 MW capacity and 1 MW/minute ramp rate, it can be awarded 15 MW ramping capability over in an FMM interval. This can be converted to an average of 5 MW 5-minute ramping capability. The difference between the FMM 5 MW awards will be settled at the RTD flexible ramping price. If the resource is awarded 4 MW

5-minute ramping capability in RTD, the resource must pay back the 1 MW at the RTD flexible ramping price.

7.1.3.1.3   Demand Curve to Meet Uncertainty

The ISO will procure additional flexible ramping capability using a surplus demand curve to meet the upper (upward) and lower (downward) flexible ramping uncertainty requirements. The amount of surplus flexible ramping procured in both the FMM and RTD markets is dependent on (1) the incremental amount of upward and downward flexible ramp needed to account for net demand forecast uncertainty of the next market run's binding interval (i.e. uncertainty requirement), and (2) the market price of supplying the additional flexible ramping capability to the markets.

Incremental upward and downward uncertainty requirements are provided via a 30-day histogram that tracks the net forecast error for each hour of the day. These requirements are posted the day prior. Note that the market will not require flexible ramping capacity for a given direction (up or down) when the net demand forecast movement exceeds the uncertainty requirement in the opposite direction.

For example, Figure 1(a) shows the net demand forecast movement is 200 MW in the upward direction. The upper (or upward) uncertainty requirement is 50 MW and shall be considered by the upward surplus demand curve. The lower (or downward) uncertainty requirement for that interval is 220 MW. In this case, only the amount of lower uncertainty in excess of the forecast movement will be considered for the downward surplus demand curve (which is 20 MW). If the downward uncertainty were below 200 MW for that interval, downward flexible ramping capability would not be required.
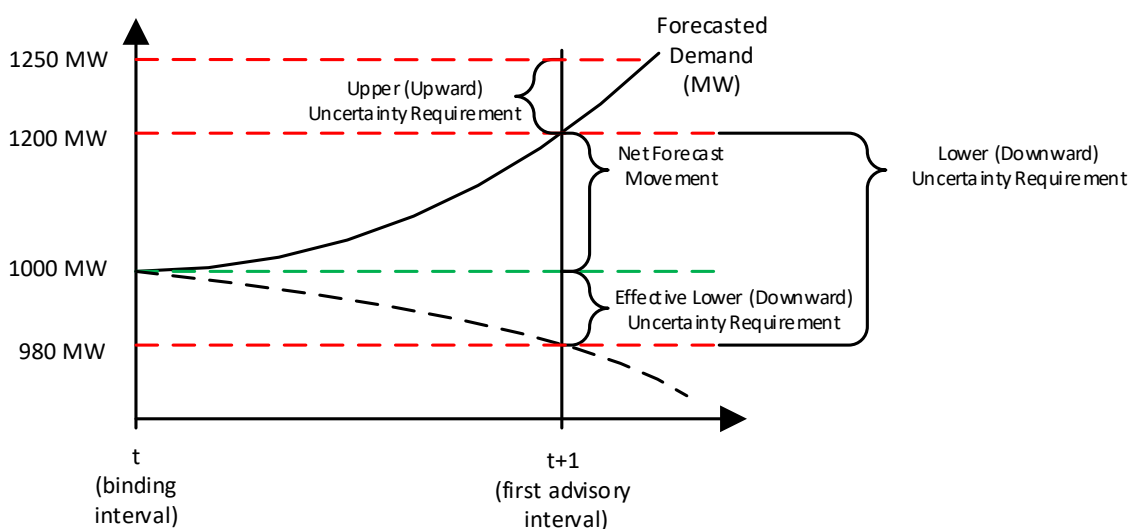
Figure 1 Flexible Ramping Product Uncertainty Requirements

The flexible ramping surplus demand curve will establish the price of not fulfilling the flexible ramping requirement for a given hour over a trade date by applying the flexible ramping cap price to the probability density function from the uncertainty histogram. This allows the market energy price to determine whether all or some of the upward and downward uncertainty requirements are met. In other words, if the energy price is lower than the expected cost of not meeting the flexible ramping uncertainty requirement, more FRP will be procured to cover the ramping requirement uncertainty. Conversely, if the market energy price is above the expected cost, then no additional FRP will be procured to cover the ramping uncertainty requirement.

Figure 2 below shows how the final construction of upward and downward flexible ramping surplus demand curves. Both an upward and downward curve is provided separately for each of the FMM and RTD markets.
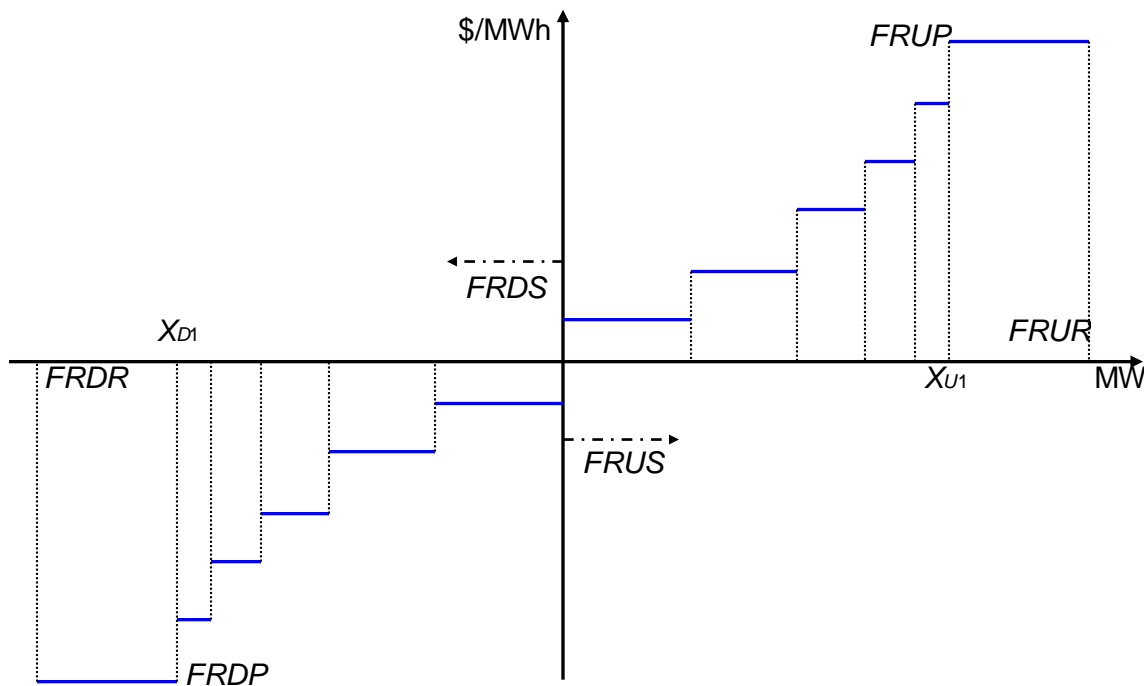
Figure 2 Flexible Ramping Surplus Demand Curves (Upward and Downward)

Where,
      FRDS = Flexible ramp down surplus capability
      FRDP = Administrative flexible ramp down price floor (FRDP = −$247/MWh)
      FRDR = Total flexible ramp down requirement (non-positive)
      FRUS = Flexible ramp up surplus capability.

FRUP = Administrative flexible ramp up price ceiling (FRUP = \$247/MWh)
FRUR = Total flexible ramp up requirement
X_{D1} = Lowest net forecast error for negative histogram bin j
X_{U1} = Highest net forecast error for positive histogram bin i

The ISO will construct histograms as an approximation of the probability distribution of net demand forecast errors to be used to procure for uncertainty. It will construct separate histograms for FRU and FRD for each hour, separately for RTD and FMM.

The histogram for RTD will be constructed by comparing the net demand for the first advisory RTD interval to the net load in the same time interval for the next financially binding RTD run. Figure 3 shows two consecutive RTD 5-minute market runs, RTD_1 and RTD_2. The ISO will construct the histograms by subtracting the net demand from the first market run used for the first advisory interval (A1) from the net demand the second market run used for the binding interval (B_2).

RTD_1

B_1

A_1

RTD_2

B_2

A_2

$B_2 - A_1$
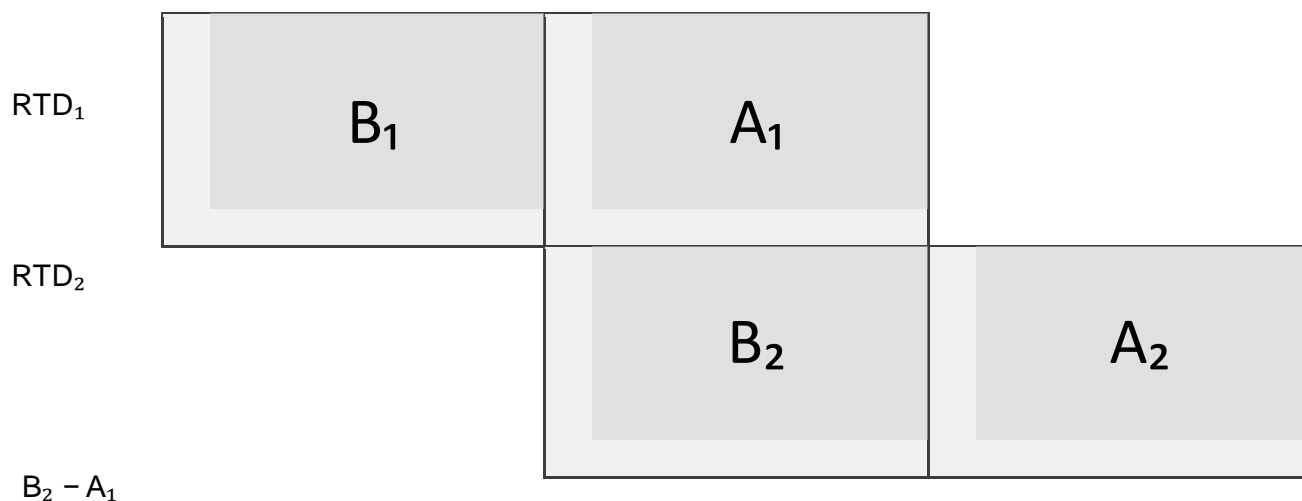
Figure 3: RTD Histogram Construction

For FMM, the ISO will construct separate histograms for FRU and FRD.

- For FRU, the histograms will be constructed based on the difference of the net demand the market used in the FMM for the first advisory RTUC interval and the maximum net demand the market used for the three corresponding RTD intervals.

- For FRD, the histograms will be constructed based on the difference of the net demand the market used in the FMM for the first advisory RTUC interval and the minimum net demand the market used for the three corresponding RTD intervals.

Figure 4 below shows two RTUC intervals: the FMM (i.e. the RTUC binding interval) and the first advisory interval (labeled "A"). It illustrates how the FRU histogram will be constructed by comparing the net demand the FMM used for first advisory RTUC interval to the maximum net demand the market used for the corresponding three RTD binding intervals (b_1, b_2, b_3).
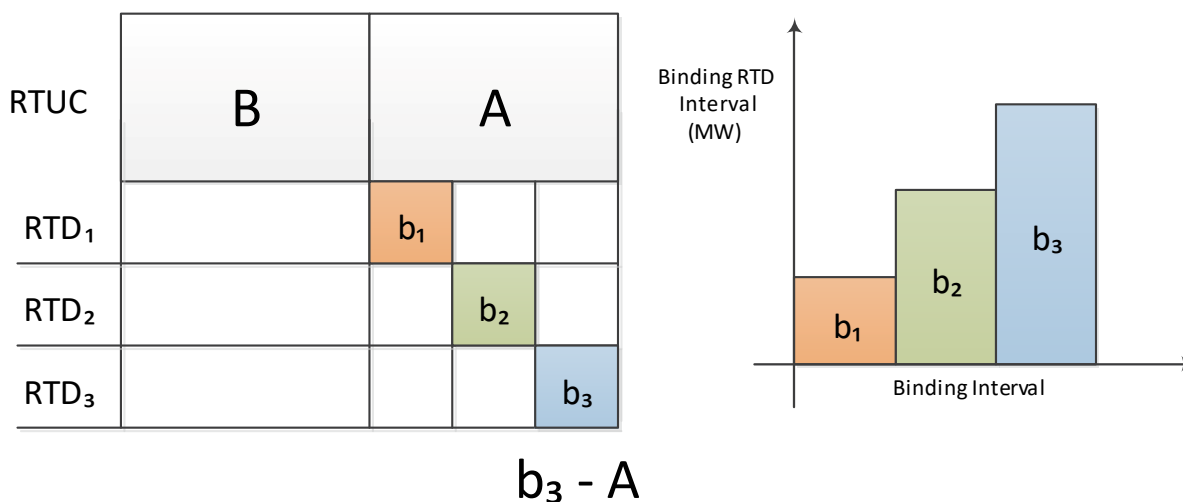
Figure 4: Histogram construction in FMM

The FRU histogram will use the observation b_3 – A. This represents the maximum ramping need. The variable b_3, represents the maximum net load in the three RTD intervals. The FRD histogram will use observation b_1 – A as this is the minimum ramping need. Ultimately in this example, the FRD observation is positive and therefore will not be used directly in the demand curve creation. It will however be used to calculate the 95th percentile load forecast error and therefore needs to be captured in the histogram.

The ISO shall use a rolling 30 day average, with a separate histogram for weekends and holidays, to evaluate the historical advisory RTUC imbalance energy requirement error pattern for each RTUC hour. The ISO will also evaluate if hours with similar ramping patterns could be combined to increase the sample size used in the historical analysis. The ISO expects that the estimate of uncertainty will improve over time. Therefore, the actual method of calculating the demand curve will be included in the business practice manual versus including these details in the tariff.

7.1.3.1.4 Examples
This section presents simple examples of FRP to demonstrate the properties and benefits of flexible ramping under the assumption that net load is accurately predicted.

For simplicity, the examples will only consider the interaction between energy and the flexible ramping product, and ignore ancillary services.

Upward flexible ramping

Assume there are two 500 MW online resources in the system that could provide FRU. The bids and parameters of the two generators are listed in Table 1. G1 has 100 MW/minute ramp rate, and G2 has 10 MW/minute ramp rate. G1 is more economic in energy than G2. They both have zero cost bids for providing flexible ramping.

Table 1: Resource bids, initial condition and operational parameters

Generation	Energy Bid	Initial Energy	Ramp Rate	Pmin	Pmax
G1	$25	400 MW	100 MW	0	500 MW
G2	$30	0	10 MW	0	500 MW

Scenario 1: Single interval RTD optimization without upward flexible ramping with load at 420 MW.

In scenario 1, load is met by the most economic resource G1, and G1 sets the LMP at $25.

Table 2: Single-interval RTD dispatch without upward flexible ramping

	Interval t (LMP=$25)	
Generation	Energy	Flexramp up
G1	420 MW	-
G2	0 MW	-

Scenario 2: Single interval RTD optimization with upward flexible ramping with load at 420 MW and an upward flexible ramping requirement at 170 MW.

The solution for scenario 2 is listed in Table 3. In scenario 2, in order to meet 170 MW upward flexible ramping, G1 is not dispatched for as much energy to make room for upward flexible ramping. As a result, G1 does not have extra capacity to meet extra load, and LMP is set by G2

at \$30. The upward flexible ramping requirement caused the LMP to increase compared with scenario 1. FRU price is set by G1's energy opportunity cost \$30 – \$25= \$5.

Table 3: Single-interval RTD dispatch with upward flexible ramping

	Interval t(LMP=$30, FRUP=$5)	
Generation	**Energy**	**Flexramp up**
G1	380 MW	120 MW
G2	40 MW	50 MW

Scenario 3: Two-interval RTD optimization without upward flexible ramping with load (t) at 420 MW and load (t+5) at 590 MW.

The solution for scenario 3 is listed in Table 4. In scenario 3, there is no flexible ramping requirement. However, the look-ahead optimization projects a 170 MW of upward load ramp from interval t to t+5, which equals the upward flexible ramping requirement in scenario 2. The look ahead optimization produces the same dispatch for interval t as in scenario 2, but different LMPs. The LMPs are different because there is an interaction between the energy price and flexible ramping price. Without the flexible ramping product, the look-ahead optimization still holds G1 back in interval t to meet the load in interval t+5, but G1 is still the marginal unit in interval t and sets the LMP at \$25.   G2 is the marginal unit for interval t+5 and sets the non-binding LMP for interval t+5 at \$35 (\$30 bid cost in interval t+5 plus \$5 not bid cost not recovered in interval t).

Table 4: Look-ahead RTD dispatch without upward flexible ramping

	Interval t (LMP=$25)	Interval t+5 (LMP=$35)
Generation	**Energy**	**Energy**
G1	380 MW	500 MW
G2	40 MW	90 MW

Scenario 4: Two-interval RTD optimization with upward flexible ramping with load (t) at 420 MW and load (t+5) at 590 MW. The upward flexible ramping requirement at (t) is 170.01 MW.

In scenario 4, both flexible ramping and look-ahead are modeled in the optimization. In order to have uniquely determined prices, we set upward flexible ramping requirement slightly higher

than expected load ramp 170 MW. The results are listed in Table 5 which converge to scenario 2 in the first interval. If the flexible ramping requirement is slightly lower than the expected load ramp, the solution would converge to scenario 3.

Table 5: Look-ahead RTD dispatch with FRU requirement slightly higher than expected upward load ramp

Generation	Interval t (LMP=$30, FRUP=$5)		Interval t+5 (LMP=$30)	
	Energy	Flex-ramp up	Energy	Flex-ramp up
G1	379.99 MW	120.01 MW	500 MW	-
G2	40.01 MW	50 MW	90 MW	-

Table 6: Possible look-ahead RTD dispatch without flexible ramping in the interval T+5

Interval t+5	Load = 589.99 MW	Load = 590.01 MW
G1	500 MW	500 MW
G2	89.99 MW	90 MW
LMP	$30/MWh	$1000/MWh

Downward flexible ramping

Assume two 500 MW resources are online in the system that can provide flexible ramping. The bids and parameters of the two generators are listed in Table 7. G1 has 10 MW/minute ramp rate, and G2 has 100 MW/minute ramp rate. G1 is more economic in energy than G2. They both have zero cost for providing flexible ramping.

Table 7: Resource bids, initial condition and operational parameters

Generation	Energy Bid	Flex Ramp Up	Flex-Ramp Down	Energy Initial	Ramp rate	Pmin	Pmax
G1	$25	0	0	300 MW	10MW/min	0	500
G2	$30	0	0	100 MW	100MW/min	0	500

Scenario 1: Single interval RTD optimization without downward flexible ramping with load at t = 380 MW

The solution for scenario 1 is listed in Table 8. In scenario 1, load is met by both G1 and G2, and G2 sets the LMP at $30. Although G1 is more economic than G2, its output 350 MW has been limited by its ramp rate 10 MW/minute from its initial condition 300 MW, so it cannot set the LMP.

Table 8: Single-interval RTD dispatch without downward flexible ramping

	Interval t (LMP=$30)	
Generation	**Energy**	**Flexramp down**
G1	350 MW	-
G2	30 MW	-

Scenario 2: Single interval RTD optimization with downward flexible ramping with load at t =

380 MW and downward flexible ramping requirement at t = 170 MW

The solution for scenario 2 is listed in Table 9. In scenario 2, in order to meet 170 MW downward flexible ramping, G2 needs to be dispatched up in order to provide downward flexible ramping. As a result, G1's output will be reduced in order to maintain the power balance, and G1 sets the LMP at $25. Note the downward flexible ramping requirement causes the LMP to decrease compared with scenario 1. The downward flexible ramping price FRDP is set by G2's energy price deficit $30 – $25= $5. The FRDP price is to compensate G2 such that G2's

revenue including both energy and FRD can cover its energy bid cost $30. As a result, there is no revenue shortage for G2, and no need for bid cost recovery.

Table 9: Single-interval RTD dispatch with downward flexible ramping

	Interval t (LMP=$25, FRDP=$5)	
Generation	**Energy**	**Flex-ramp down**
G1	260 MW	50 MW
G2	120 MW	120 MW

Scenario 3: Two-interval RTD optimization without downward flexible ramping with load at t = 380 MW and load at t+5 = 210 MW.

The solution for scenario 3 is listed in Table 10. In scenario 3, there is no FRD requirement. However, the look-ahead optimization projects a 170 MW of downward load ramp from interval t to t+5, which equals the downward flexible ramping requirement in scenario 2. The look-ahead optimization produces the same dispatch for interval t as in scenario 2, but different LMPs. The dispatch is the same because the look-ahead load ramp also requires the same amount of ramping capability as the flexible ramping requirement in interval t. The LMPs are different because there is an interaction between the energy price and flexible ramping price. When net system demand is decreasing, which creates more downward ramp need, the look-ahead optimization will increase the energy price in the binding interval (for similar but opposite reasons as described in the FRU example in scenario 3 in the preceding section 6.1).

Table 10: Look-ahead RTD dispatch without downward flexible ramping

	Interval t (LMP=$30)		Interval t+5 (LMP=$20)	
Generation	**Energy**	**Flex-ramp down**	**Energy**	**Flex-ramp down**
G1	260 MW	-	210 MW	-

G2	120 MW	-	0	-

Scenario 4: Two-interval RTD optimization with downward flexible ramping with load t = 380 MW and load at t+5 = 210 MW. The downward flexible ramping requirement at (t) is 170.01.

In scenario 4, both flexible ramping and look-ahead are modeled in the optimization. In order to have uniquely determined prices, we set downward flexible ramping requirement slightly higher than expected load ramp 170 MW. The solution for scenario 4 is listed as Table 11.

Table 11: Look-ahead RTD dispatch with FRD requirement slightly higher than expected downward load ramp

	Interval t (LMP= $25 , FRDP= $5)		terval t+5 (LMP=$25 , FRDP= $0)	
Generation	**Energy**	**Flex-ramp down**	**Energy**	**Flex-ramp down**
G1	259.99 MW	50 MW	210 MW	-
G2	120.01 MW	120.01 MW	0 MW	-

7.1.4   Schedule Changes

The hourly Schedule change rules described below are applied prior to the SCUC/SCED optimization in RTM and only when there are no Energy Bids or Exceptional Dispatch Instructions in both consecutive Trading Hours (otherwise the hourly Schedule change is calculated optimally by SCUC/SCED):

➢ All cross-hour Non-Dynamic System Resource schedule changes are performed with the standard schedule-change ramp, which is a smooth linear 20-minute ramp between hourly Schedules. If applicable, schedule changes across 15-minute intervals within the hour are performed with a smooth linear 10-minute ramp between 15-minute interval schedules.

➢ Resources with no Energy Bids or Exceptional Dispatch Instructions in consecutive hours are expected to ramp between hourly schedules symmetrically across hourly boundaries in 20 to 60 minutes (i.e., starting 10 minutes to 30 minutes before the top of the hour, respectively) consistent with the submitted and validated Ramp Rate function (incorporating any reported Outages). If a validated Ramp Rate function does not exist for a resource, RTM uses the maximum (best) Ramp Rate function from the Master File. RTM recognizes the unit's capabilities based on its Operating Point, and it does not ramp the unit at a rate higher than the applicable operational ramp rate within its current operating range. The minimum 20-minute ramp is required for smooth hourly schedule changes and is consistent with intertie scheduling agreements between Balancing Authority Areas. Resources with slower Ramp Rates would have longer ramps, and at the extreme, they would ramp from the middle of an hour to the middle of the next hour. Contrary to cross-interval Ramping, where the entire Dispatch Interval is used for Ramping, resources should ramp across hours between 20 and 60 minutes, because of Energy delivery requirements under bilateral contracts and intertie schedules, and because of Ancillary Services provision eligibility. NGRs are treated differently. If they are not supplying Energy Bids or Exceptional Dispatch Instructions in consecutive hours, they will be expected to ramp instantaneously between schedules at the hourly boundary.

7.1.4.1   Cross-Interval Ramping

The difference between the Dispatch across two consecutive intervals is limited to the ramp capability of the resource within the duration of the interval (15 minutes for FMM and 5 minutes for RTED) based on the applicable Operational Ramp Rate curve reduced by a configurable percentage of the relevant Regulation Awards in both consecutive hours. For Generating Units that start-up or shut-down in a given interval, RTM assumes that the start-up and shut-down occur at the start and end of that interval, respectively. The optimal schedule in that interval is limited to half of the ramping capability plus the relevant Minimum Load. Furthermore, for Regulation, the resource is first ramped into its regulating range at start-up before it can regulate, and it is going off Regulation then it is ramped outside of its regulating range at shut-down.

The following ramping rules apply consistently for all RTM applications:

1) The resource's Operational Ramp Rate would always be used to constrain energy schedules across time intervals irrespective of Regulation Awards. The Operational Ramp Rate may vary over the resource operating range and it incorporates any ramp rates over Forbidden Operating Regions. The fixed Regulating Ramp Rate would only be used to limit Regulation awards.

2) Hourly Intertie resource schedule changes would not be limited across hours.

3) The upward and downward ramp capability of online resources across time intervals would be limited to the duration of the time interval: 15 minutes in FMM, 5 minutes in RTED and RTMD, and 10 minutes in RTCD.

4) The upward and downward ramp capability of resources starting up or shutting down across time intervals (from or to the applicable Lower Operating Limit) would be limited to half the duration of the time interval: 7.5min in FMM, and 2.5min in RTED and RTMD.

5) The upward ramp capability of resources starting up through Fast Unit Start-Up (from the applicable Lower Operating Limit) in RTCD would be limited to the difference between 10 minutes and their Start-Up Time.

6) The upward and downward ramp capability of resources across time intervals would not be limited by capacity limits (operating or regulating limits); in that respect, the upward ramp capability would extend upwards to $+\infty$ and the downward ramp capability would extend downwards to $-\infty$ by extending the last and first segments of the Operational Ramp Rate curve beyond the resource Maximum Capacity and Minimum Load, respectively. Capacity limits would be enforced separately through the capacity constraints.

7) The upward ramp capability of resources across time intervals with Regulation Up Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor.

8) The downward ramp capability of resources across time intervals with Regulation Down Awards would be reduced by the sum of these awards over these intervals, multiplied by a configurable factor (same as above).

9) By exception, the ramp capability of resources on regulation would not be limited in RTCD.

10) The configurable factor for the upward and downward resource ramp capability reduction would be application specific (FMM, RTED and RTMD) because it would depend on the duration of the time interval.

11) In RTED, in the case a resource is awarded Regulation but the telemetry is outside the Regulation range, the resource is ramped at the Operational Ramp-Rate, with no ramp capability reduction, towards the dispatch level that is inside the Regulation range by an amount to support the awarded Regulation until the resource is actual able to support the regulation awarded.

These ramping rules result in a consistent unified treatment across all applications. Conditional ramp limits apply only to resources with Regulation Awards. No ramp capability reduction is required for Spinning or Non-Spinning Reserve Awards given that these awards are normally dispatched by RTCD where all ramp capability must be made available even at the expense of Regulation.

7.1.4.2   Multi-Stage Generating Resource Constraints

➢ The following constraints are modeled for Multi-Stage Generating Resources in addition to the typical constraints for Generating Units or Dynamic Resource-Specific System Resources:

➢ The start-up notification time will be enforced for each startup-able MSG Configuration. Start-up notification time is used to determine how far ahead the startup instruction has to be issued.

➢ The MSG Configuration transition parameters may differ for each feasible transition. The feasible transitions have specified transition notification times, transition ramp times, and Transition Costs in the Master File.

➢ The SCUC optimization process considers bid-in costs (including Energy Bids and Ancillary Services Bids, Start-Up Costs, Minimum Load Costs, and Transition Costs.

➢ The MSG model optimally assigns Self-Schedule to one MSG Configuration among all MSG Configurations associated with a particular MSG plant.

➢ The Energy Limit values are specified at the plant level and are enforced at the plant level if defined. In both the RTM and DAM, the Energy Limit calculation will include the transitional Energy between two configurations.

➢ The MUT, MDT and SUT constraints are ignored for resources that have bid only Self Schedules for the entire optimization horizon.

➢ Multi-Stage Generating Resources may also specify the daily maximum number of transitions per direction between the on-line configurations. This number defines how many times the MSG resource can be transitioned from one MSG Configuration to another.

➢ Transition notification time: the notification time represents the time required to be notified in advance of the end of the transition to another MSG Configuration. As a consequence, notification time includes the transition ramp time. When switching a MSG Configuration, the MSG needs the transition specific notification time. During the

notification time and while not in transition, the MSG resource is available for dispatch and Ancillary Service Award. During a transition ramping time, the Multi-Stage Generation Resource cannot provide Ancillary Services. For Real-Time Unit Commitment, notification time applies only for online to online configuration transitions. If a Multi-Stage Generation Resource is not online, notification time does not apply and the standard configuration based start-up process applies.

➢ FMM will use these constraints in observing Day-Ahead Schedules. When the Day-Ahead Market commits the Multi-Stage Generating Resource into a specific MSG Configuration, the later FMM run will check to make sure that the Multi-Stage Generating Resource does not move to another MSG Configuration or offline such that the inter-temporal constraints will prevent the Multi-Stage Generating Resource from observing the MSG Configuration specified by the Day-Ahead Schedule.

7.1.4.3   The Current State and Initial Condition Determination

The Real-Time Dispatch will determine the initial condition for Multi-Stage Generating Resources. The Real-Time Dispatch determines which MSG Configuration the Multi-Stage Generating Resource is operating in for the initial condition of the market time horizon. Some of the Multi-Stage Generating Resources have the capability to notify the currently running MSG Configuration through EMS. This option is provided via a Master File flag. If the MSG plant does not have this capability the currently running MSG Configuration needs to be determined by using the look-up table that contains the number of Combustion Turbines and Steam Turbines connected to the system and their combined power output that maps them to an MSG Configuration.

The following sample data demonstrates this process: Combined Cycle plant ABC has two combustion turbines and one steam unit and has four configurations.

MSG PLANT	MSG CONFIGURATION	NUMBER OF CTs	NUMBER OF STs	RESULTANT LOW MW CAPACITY (Configuration Pmin)	RESULTANT HIGH MW CAPACITY (Configuration Pmax)
ABC	1	1	0	0	100
ABC	2	2	0	100	200
ABC	3	1	1	0	150

ABC	4	2	1	100	250

Each Configuration is identified by the number of the combustion turbine and steam turbine connected to the system. The Real-Time Market application will read the telemetry data and determine how many gas and steam turbines are currently connected to the system and their combined MW output.

In cases where the telemetry data indicates a MW level that falls within an overlap region between two configurations, the MSG Configuration from the previous market run will be used to determine the initial condition configuration for the current run. The MSG resource will remain in its previous state until the telemetry MW eventually falls outside the configuration's range.

The determination if the plant is 'In State' or 'In Transition' is based on the Generating Unit telemetry information. If the telemetry information suggests that the Generating Unit is present in one of the available configurations, the Generating Unit's initial condition is tagged 'In State' (IS). If the telemetry information suggests that the Generating Unit is not in any of the MSG Configurations and is in between configurations, the Generator is tagged 'In-Transition' (IT).

7.1.4.4   Multi-Stage Generating Resource Transition Profile

The Multi-Stage Generating Resource will transit from one MSG Configuration to another by using a transition profile consisting of MW value and time. The MSG Transitions are of two types: Non-overlapping and overlapping type.

Non-Overlapping Transition:

Consider a case where there are gaps in the operating range between the two consecutive MSG Configurations. Let S_1 be the state from which the transition is starting having the operating range $PMin_1$ and $PMax_1$ and S_2 is the state from where the transition is ending have the operating range $PMin_2$ and $PMax_2$ such that $PMin_1 \leq PMax_1 < PMin_2 \leq PMax_2$.

When transitioning from S1 to S2 the state transition starts from PMax1 and ends at PMin2 using the transition time specified in the Master File. The Day-Ahead Market and Real-Time Market will calculate the linear ramping profile using the transition time for internal imbalance consideration. The dispatch will stay at the closest boundary of the "from" configuration until the transition is complete.

Overlapping Transition:

In this case there are no gaps in the operating range between the two consecutive MSG Configurations. Let S1 be the state from which the transition is starting have the operating range

PMin1 and PMax1 and S2 is the state from where the transition is ending have the operating range PMin2 and PMax2 such that PMin1 ≤ PMin2 ≤ PMax1 ≤ PMax2 .

When transitioning from S1 to S2 the transition begins and ends in [PMin2, PMax1] and vice versa using the transition time specified in the Master File. The transition will be done by using a pre-calculated transition profile using the transition time for the binding and advisory intervals. The granularity of the transition profile will be same as the time interval of the specific application. The transition profile in this case will be straight line at the middle of the overlapping transition region. As an example if a Multi-Stage Generating Resource has two MSG Configurations as (20-100) MW and (80-200) MW, the transition profile will be a straight line at 90 for the transition time. For overlapping transitions, the dispatch will be assumed at the middle MW level of the overlapping transition region until the transition is complete.

In cases where the transition time is less than the particular application's time interval the instantaneous transition will be achieved. Also, in cases where the lower limits of the higher MSG Configuration and the higher limit of the lower MSG Configuration coincide with each other, and the transition time is zero, then the transition is instantaneous.

7.1.5   Dispatch Priorities

SCUC and SCED alert the CAISO Operator with the aggregate Load increase or reduction in the penalty region for each defined LAP so that the CAISO Operator can procure the required Imbalance Energy through an Exceptional Dispatch.

The SCUC/SCED software provides the functionality to classify and prioritize constraints among themselves and the resource Dispatch priorities. The priority level for any resource or Constraint class is configurable. Resource and Constraint classes may share the same priority level. The penalty prices for all resource priorities, i.e., the price of uneconomic Bid segments for resource bids, e.g., Self-Schedules, RMR dispatches, contingent spin/non-spin, etc., and the penalty prices for Constraint violations are coordinated through the parameter maintenance effort.

The CAISO through the simultaneous optimization to the extent possible will attempt to enforce constraints using Effective Economic Bids. In the event that such constraint(s) are binding and cannot be resolved using Effective Economic Bids and there are conflicting constraints, the CAISO will resolve such conflicting constraints in the priority order mentioned below. The following constraint classes are supported and in the following priority order from high to low:

➢ Power Balance Constraint

➢ Base case transmission constraints (separate levels for branch flows, interface flows, and Nomograms)

➢ Contingency constraints (branch flows)

➢ Ancillary Services minimum regional requirements

➢ Ancillary Services maximum regional requirements

The SCUC/SCED software is configured to incorporate any transmission constraint limit adjustments made by CAISO operators to respond to system conditions. The CAISO operators make these adjustments in accordance with section 2.1.1 of the Business Practice Manual for Managing Full Network Model. When a limit is manually adjusted or conformed, the market software will automatically determine if the newly conformed limit is feasible or within the ramping capability in the market. If the newly conformed limit is not feasible or beyond the ramping capability to resolve the constraint, the market optimization will adjust the conformed limit as needed such that the conformed limit will be feasible or the ramping capability will be sufficient to resolve the constraint.

7.1.6   RTM Self-Schedules

Resources may self-schedule in the RTM in addition to or without providing Energy Bids. Resources with Day-Ahead Schedules that do not Bid in the RTM, are assumed to be self-scheduling their Day-Ahead Schedules. However, Energy Bids are required for resources that have AS or RUC Awards, Bid or Self-Provided AS, or are under a Resource Adequacy Obligation. In order to get TOR/ETC priorities in RTM, resources need to re-submit self-schedules of type 'ETC' or 'TOR' in RTM. Otherwise, Day-Ahead Schedules of resources roll into RTM and are protected in RTM at Self-Schedule priority and not at 'ETC' or 'TOR' priority.

A Self-Schedule from a resource that is not committed in the DAM indicates self-commitment, i.e., the RTM does not de-commit Self-Scheduled resources. Conversely, a Self-Schedule cleared in the RTM for a resource committed by the CAISO in DA does not constitute a Self-Commitment. The RTM also does not de-commit resources with Ancillary Services Awards. The Self-Schedule, although at a higher scheduling priority than Energy Bids, may be reduced by the RTM if this is necessary to resolve network constraints. Self-Schedules may also be adjusted by the RTM as necessary to resolve any resource operational or inter-temporal Constraint violations.

The Self-Schedule is modeled as an Energy Bid with a penalty price that effectively provides scheduling priority over economic Energy Bids. The penalty price is only for modeling purposes and it does not affect the Energy component of the LMP, which is calculated by the pricing run. For Settlement purposes, RTM Self-Schedules are Price Takers; (i.e., their Energy deviation from the DAM Schedule is settled at the relevant LMP).

As described in CAISO Tariff Section 34.10.1, Increasing Supply, there are several different types of Self-Schedules at different scheduling priorities. The scheduling priorities as defined in the RTM optimization to meet the need for increasing Supply as reflected from higher to lower priority are as follows:

➢ Non-Participating Load reduction (power balance constraint slack)

➢ Economic Bids submitted in the RTM, including Contingency Only Operating Reserve if activated by the CAISO Operator to provide Energy (as indicated by the Contingency Flag and the Contingency condition)

As outlined in CAISO Tariff Section 34.10.2, Decreasing Supply, the scheduling priorities as defined in the RTM optimization to meet the need for decreasing Supply as reflected from higher to lower priority are as follows:

➢ Non-Participating Load increase[29] (power balance constraint slack)
➢ Reliability Must Run (RMR) Dispatches
➢ Transmission Ownership Right (TOR) Self-Schedules
➢ Existing transmission Contact (ETC) Self-Schedules
➢ Regulatory Must Run and Regulatory Must Take (RMT) Generation Self-Schedules
➢ Participating Load increase
➢ Day-Ahead Supply Schedule
➢ Self-Schedule submitted in the RTM
➢ Economic Bids submitted in the RTM

These dispatch priorities as defined in the RTM optimization may be superseded by CAISO Operator actions and procedures. A variety of conditions may require CAISO discretionary actions, for example if the Operator needs to take action to maintain reliability or to execute an Exceptional Dispatch.

If an Energy Bid is submitted with a Self-Schedule from the same resource for the same Trading Hour, the Energy Bid must start at the end of all relevant Self-Schedules stacked back-to-back

---

[29] To the extent that "non-participating load increase" physically occurs, it would be through out-of-market sales of excess supply, since in-market remedies have already been exhausted.

in decreasing scheduling priority order. Otherwise, the Energy Bid must start at the applicable Minimum Load (zero for System Resources).

Self-committed resources are not eligible for recovery of their Start-Up Costs. Self-committed resources are also not eligible for recovery of their Minimum Load Costs during the Trading Hours when they self-schedule. However, they are still eligible for conditional recovery of unrecovered Bid Costs through the Bid Cost Recovery mechanism in Settlement.

Since Self-Provided Ancillary Services can be submitted only at the MSG Configuration for a given Trading Hour and since it is possible that that Multi-Stage Generating Resource can actually support the Self-Provided Ancillary Service amount from other configurations, Self-Provided Ancillary Service quantities are treated as plant level quantities in the Real-Time Market. In order to accomplish this, the Self-Provided Ancillary Services on the originally submitted MSG Configuration is propagated to other Ancillary Services certified MSG Configurations for the optimization to consider in the following steps:

> Step 1: Perform the Ancillary Services qualification process on the submitted MSG Configuration in the same manner as for non-Multi-Stage Generating Resources, except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

> Step 2: Transfer the qualified Ancillary Services self provision MW to other MSG Configurations with Ancillary Services certification in the same service product if these configurations have Energy Bids for that given Trading Hour. This transferred Ancillary Services self provision MW is determined by the following formula per transferred MSG Configuration,

> > Transferred Self-Provided Ancillary Services = Minimum (final qualified Self-Provided Ancillary Service of bid in MSG Configuration, certified Ancillary Services capacity of transferred MSG Configuration)

> Step 3: On the transferred MSG Configuration, the transferred Self-Provided Ancillary Services amount determined from step 2 will then be further qualified using the same rules in capacity and ramping qualification as for non-Multi-Stage Generating Resources (see section 4.2.1), except using the MSG Configuration's parameters such as ramp-rate, PMin and PMax.

The Multi-Stage Generating Resource will be allowed to submit a Self-Schedule on only one MSG Configuration per given Trading Hour. However, this Self-Schedule reflects the Multi-Stage Generating Resource's intention to operate at or no lower than a certain MW level, not an intention to operate in a particular MSG Configuration. Consequentially, any one of the MSG Configurations may be committed if there is a self-schedule on any of the MSG Configurations

within the same Multi-Stage Generating Resource.   Once submitted, the Self-Schedule is associated with all MSG Configurations of the Multi-Stage Generating Resource that have a Minimum Load below or equal to the Self-Schedule quantity. In order to provide for fair economic choice among MSG Configurations there will be adjustments to Start-Up Cost, Minimum Load Cost and related Transition Costs of affected configurations as listed below.

The rules given below apply to self-schedules:

1. For the MSG Configuration with a PMin higher than the Self-Schedule MW:

   - The Minimum Load Cost will be taken into account when considering commitment of the configuration, but will be reduced to only reflect cost of minimum load not consumed by Self-Scheduled quantity, i.e. will be equal to Max(0, Minimum Load Cost of the transferred configuration - Minimum Load Cost of the submitted MSG Configuration);

   - the Start-Up Cost will be taken into account when considering commitment of the MSG Configuration;

   - Transition Cost for any transition that is incident (incoming or outgoing) into/from the MSG Configuration will be considered unless conflicting with rules 2 and 3 below.

2. For the MSG Configuration with a PMin lower than or equal to the Self-Schedule MW and a PMax higher than or equal to the Self-Schedule MW:

   - Start-Up Costs and Minimum Load Costs are treated as must-run resources (i.e. there is no Start-Up Cost and no Minimum Load Cost);

   - Ignore Transition Costs for incoming transitions;

   - Consider Transition Costs for outgoing transitions.

3. For the MSG Configuration with a PMax lower than the Self-Schedule MW:

   - Ignore Start-Up Costs;

   - Minimum Load Cost treatment is the same as in (2) above;

   - Ignore Transition Cost for any transition incident to the particular configuration.

7.1.7   Calculation of MCP

Exhibit 7-2 illustrates how the Market Clearing Price for Energy for a HASP time interval is calculated for the case with no Marginal Losses and no Congestion. In this scenario all the LMPs for Energy have the same value, equal to the MCP.

The major difference between this exhibit and the corresponding Exhibit 6-3 for DAM is that RTM has no Demand Bids. Therefore the MCP is established by the Supply curve and the total Real-Time Demand.

Exhibit 7-2: Real-Time Market Clearing Price for Energy (Ignoring Marginal Losses & Congestion)
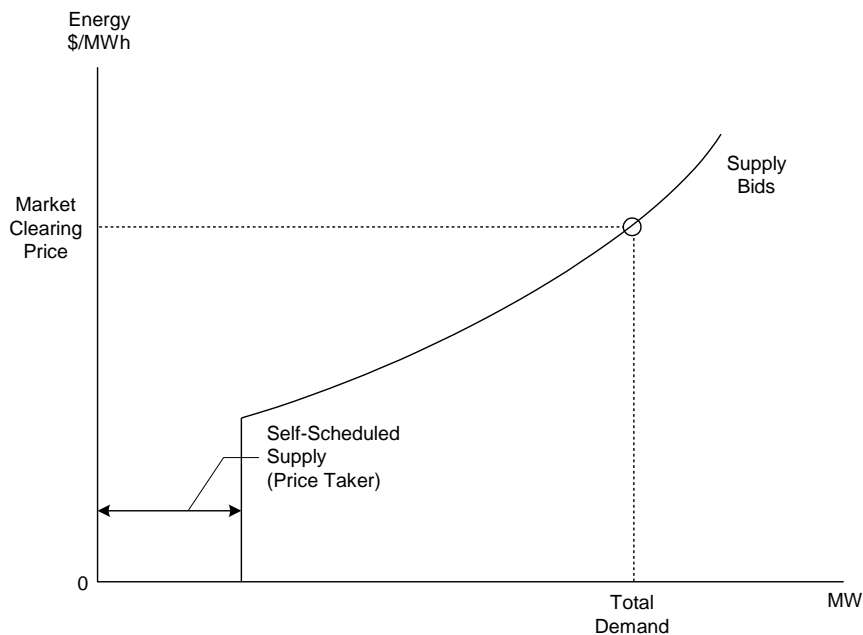
7.2   Scheduling Coordinator Activities

The SCs are the entities that interact directly with the RTM. They are responsible for submitting Bids into the CAISO Markets and to respond to the directives of CAISO, resulting from the CAISO Markets. All Settlement and billing is conducted between CAISO and the SCs.

7.2.1 Submit Bids

This section is based on CAISO Tariff Section 34.1.3, Submission of Bids for the RTM.

SCs may submit Bids that are used for the RTM processes starting from the time Day-Ahead Schedules are posted until 75 minutes prior to each applicable Trading Hour in the Trading Day. The rules for submitted Bids specified in Section 30 of the CAISO Tariff apply to Bids submitted to the RTM.

After the bidding closes for the RTM for a Trading Hour, CAISO performs a validation process consistent with the provisions set forth in Section 30.7 of the CAISO Tariff, and described in more detail in the *BPM for Market Instruments, Section 8*.

Bids submitted to the RTM to supply Energy and Ancillary Services are considered in the various RTM processes, including the MPM process, the HASP, the STUC, the RTUC, the FMM, the RTED, the RTCD, and the RTMD.

CAISO allows RTM Self-Scheduled firm exports to the extent the firm export is being physically sourced from a resource that is not obligated to serve CAISO Demand (i.e., capacity being committed to Resource Adequacy, RUC Award, or RMR). Validation and accommodation for such Self-Scheduled firm exports requires a manual process.

Refer to the *BPM for Market Instruments* for additional bidding details.

7.2.2 Interchange Transactions & ~~e-Tag~~E-Tagging

When submitting interchange transactions in the RTM, it is necessary to create an ~~e-Tag~~E-Tag. An ~~e-Tag~~E-Tag is required for all Energy Schedules and AS Awards at Scheduling Points, in accordance with NERC and WECC specifications. See section 8.0 for more information on tagging. ~~The following e-Tags are used:~~

> ~~Ancillary Service Bids — For the capacity e-Tag, the Energy profile equals zero. However, the transmission allocation profile is equal to the AS Award for DAM and equal to the AS offer in the RTM. When the AS is converted to Energy, the MW profile is increased accordingly.~~

> ~~Energy Schedules~~

> ~~Energy Self-Schedules including ETC and TOR Self-Schedules.~~

~~To enable CAISO to match the e-Tags with the relevant Balancing Authority Area Operator, the following market information must be included on each e-Tag:~~

> ➤ Scheduling Coordinator ID

> ➤ Energy Type

> ➤ Transmission Right Identifier, i.e., Contract Reference Number (CRN), if applicable

> ➤ Resource ID.

If an e-Tag is submitted before RTM is final and is correct, the e-Tag is approved with the following disclaimer. If RTM clears at a lower MW value than the tag's transmission allocation, then the e-Tag is adjusted down to match the RTM output.

7.2.2.1   e-TagE-Tagging Timelines and Rules

See section 8.0 for more information on rules and timelines.For all intertie schedules, the e-Tag must be submitted by twenty minutes prior to the applicable Trading Hour.   For all bid types except FMM Economic Bids, the transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the award from HASP or the Self-Schedule, as appropriate.   For FMM Economic Bids, the transmission profile must be greater than or equal to the maximum bid-in capacity for the Trading Hour, and the Energy profile must equal the MWs awarded for the first FMM interval of the Operating Hour.

For bid types that may vary by 15-minute interval, including FMM Economic Bids and Economic Hourly Block Bids with Intra-Hour Option, the Energy profile must be updated to reflect any schedule changes by twenty minutes before the start of the FMM interval to which the Schedule change applies. In the absence of extenuating circumstances, the ISO automatically will update Energy profiles on E-tags for Energy Schedules that change from HASP to the FMM within a Trading Hour. However, it is ultimately the responsibility of the Scheduling Coordinator to ensure that the E-tag Energy profile reflects the delivered quantity. The changed energy profile will apply for the balance of the operating hour unless it is subsequently changed by a further updated energy profile.

For FMM Economic Bids, if the Scheduling Coordinator intends to limit its participation in the FMM to the quantity in the HASP advisory energy schedule (including zero), the Scheduling Coordinator may update its transmission profile to the maximum amount it wants to make available to the FMM prior to the start of the binding FMM optimization, which is no earlier than thirty-seven and a half minutes before the applicable Trading Hour.   If the Scheduling Coordinator does not have a transmission profile greater than or equal to its advisory Energy schedule, the resource cannot be scheduled for Energy in the FMM for amounts greater than what is listed in the transmission profile.

7.2.3   Respond to Commitment & Dispatch Instructions

Upon publication of Schedules and Awards, SCs are advised to review the Schedules and Awards in order to be prepared to respond to Dispatch Instructions issued from ADS and CMRI. Start-Up Instructions may be issued by the CAISO before Dispatch Instructions are issued, which require resources to Start-Up prior to the relevant Dispatch Interval. Resources must be started in time for the resource to be available for the Dispatch Interval for which they are committed. The following instructions result from the Real-Time applications.

7.2.3.1   Commitment Instructions

Binding commitment instructions are generated and sent through ADS every 15 minutes from RTUC for dispatchable resource. Shut-Down instructions in the first interval of the RTUC Time Horizon are always binding. Shut-Down instructions in subsequent intervals are advisory and thus not sent through ADS. Start-Up instructions are binding if they cannot be revised in subsequent RTUC runs due to the relevant Start-Up Time. Only binding Start-Up instructions are sent through ADS. Transition Instructions are binding if they cannot be revised in subsequent Real-Time Unit Commitment runs due to the relevant transition notification time. Only binding transition instructions are sent through ADS

7.2.3.2   Ancillary Service Awards

AS Awards are generated and sent through ADS and CMRI for all resources except Non-Dynamic System Resources that have submitted any type of hourly block bids every fifteen minutes, as required for dispatchable resources. For Non-Dynamic System Resources that have submitted hourly block bids, AS awards will be sent to ADS and CMRI for the target hour once an hour after each associated HASP run. The AS Award separately identifies the Day-Ahead Award, the Real-Time qualified self-provision, and the Real-Time AS Awarded Bid. Any Real-Time Award for Spinning and Non-Spinning Reserve are considered Contingency Only. AS procurement in the RTM is done optimally based on system conditions during each 15-minute FMM interval. Because the CAISO must then maintain adequate reserves during the 15-minute interval, with no further opportunity for AS procurement, the RTM AS Awards are protected from being dispatched by RTED through designation as "contingency only". The CAISO will not Dispatch any Energy from the associated Energy Bid if there is no Ancillary Services awarded to the Non-Dynamic System Resource. See CAISO Tariff Section 30.5.2.6 and the BPM for Market Instruments.

7.2.3.3   Exceptional Dispatch

Exceptional Dispatches can be generated and sent through ADS or issued through manual instructions. When generated through Ads, instructions are reported and updated when they are issued. These instructions arrive along with Dispatch Operating Target (DOT) and possibly Unit Commitment instructions.

It is possible that there is more than one non-conflicting Exceptional Dispatch for the same time period. ADS presents those instructions.

Refer to Section 7.11, Exceptional Dispatch, for additional information.

7.2.3.4   Dispatch Instructions

Dispatch Instructions, also referred to as Dispatch Operating Targets (DOTs), for dispatchable resources, including Dynamic System Resources, are generated and sent through ADS every five minutes (or after RTCD). Dispatch Instructions for Non-Dynamic System Resources are generated by HASP or FMM. Non-Dynamic System Resource HASP Block Intertie Schedules and FMM first interval advisory schedules are sent through ADS hourly. ~~and sent through ADS hourly or every fifteen minutes, respectively.~~ Non-Dynamic System Resources HASP Block Intertie Schedules have the option to decline or partially accept a HASP generated Dispatch Instruction subject to the assessment of a monthly penalty~~a Dispatch Instruction subject to the assessment of monthly penalty~~. There is a monthly settlement charge applied to the declined pre-dispatched instructions exceeding a pre-defined threshold MW.

7.2.3.5   Dispatch Instruction Breakdown

Each Dispatch Instruction is broken down into separate MW components. MW components include:

- ➢ SCHD: Day-Ahead Schedule
- ➢ MSSLF: MSS qualified Load Following Instruction
- ➢ RMPS: Standard Ramping Energy
- ➢ SUPP: Imbalance Energy
- ➢ SPIN: Dispatched Spinning Reserve
- ➢ NSPN: Dispatched Non-Spinning Reserve

These breakdowns are associated with their corresponding Dispatch Instructions. This DOT breakdown is published through ADS. The Operators reviews the Dispatch Instructions before they are sent to ADS and they may decide to block certain instructions based on information known to them, but unknown to the RTM application. The Operator may also block all instructions at extreme conditions when the dispatch results are incorrect.

7.2.3.6   Trajectory Data

The Dispatch Operating Point (DOP) is a piecewise linear curve defined by MW (on the Y axis) across time (on the X axis). The source data consists of the DOTs, which are published in the GOTO field in the ADS. The DOP is the expected trajectory of the resource operating point as it ramps from one DOT to the next; the ramping across Dispatch Intervals is linear, unless the operational ramp rate of the resource changes during the ramp. Since RTM dispatches resources based on their actual output as shown in the State Estimator solution or the telemetry, nearly vertical corrections to the DOP curve can occur at five-minute intervals when a previously issued DOT is corrected to the actual output. In the absence of Dispatch instructions, ADS extends the most recent DOP value available and plots a flat curve to the end of the next interval.

For Generating Units that start up or shut down in a given interval, RTM assumes that the start-up and shut-down occur at the start and end of that interval, respectively. The dispatch in that interval is limited to a ramp capability that corresponds to half of the interval duration, plus the relevant Minimum Load.

For Multi-Stage Generating Resources that are transitioning from one on-line configuration to another, the Real-Time Market assumes that the transition occurs for the time period as defined by the transition ramp time. During the transition time period, the Real-Time Market will assume the Multi-Stage Generating Resource operates in the "from" configuration until the transition is complete. More specifically:

1. During the transition between two non-overlapping configurations, the Real-Time Market will dispatch the resource to stay at the closest boundary of the "from" configuration until the transition is complete. When transition is complete, the Real-Time Market will start the dispatch at the closest boundary of the "To" configuration;

2. During the transition between two overlapping configurations, the Real-Time Market will dispatch the resource to stay at the middle MW level of the overlapping capacity range between those two configurations. When the transition is complete, the Real-Time Market will start the dispatch to ramp within the "To" configuration based on the "To" configuration's ramp-rate.

7.2.3.7   Compliance

When a resource demonstrates that it is not following Dispatch Instructions, consistent with the procedure described below, the RTM will no longer assume that the resource will comply with subsequent Dispatch Instructions.

a) General Compliance Rules

If the CAISO determines there is a need to set the DOT of resources consistent with their actual behavior because of demonstrated non-compliance with Dispatch Instructions, the CAISO will activate the compliance feature. Once activated, a resource is considered non-compliant if it is deviating by more than a threshold (set to five MW or three percent, whichever is greater) from the DOT that was issued for the same time with the timestamp of its telemetry, for more than a configurable number of consecutive intervals (initially set to three). When a resource is flagged as non-compliant, it is fixed in RTM for the entire Time Horizon at its current telemetry. However, the previous DOT that was last issued is sent through ADS. That DOT is continuously sent through ADS for as long as the resource remains non-compliant.

The resource will be considered compliant again when its telemetry comes within the threshold from the DOT for a configurable number of consecutive intervals (initially set to one). The CAISO may also set the resource to be compliant again as necessary.

When a resource has an uninstructed start-up, the resource is automatically considered non-compliant until it either shuts down or until the time of a scheduled start-up (if the resource has an uninstructed early start-up). Similar concept applies to delayed shutdown.

b) Compliance with Dispatches In and Through Forbidden Operating Region

Consistent with the requirements in Section 34.15.1(b) of the CAISO Tariff and Section 7.8.2.4 above, the compliance flag is applied to resources in all intervals of the Real-Time Market to ensure the availability of the resource in intervals, when despite a CAISO Dispatch Instruction into and through a Forbidden Operating Region, the resource never actually enters the Forbidden Operating Region. Consequently, in the event that the RTM functionality identifies that a resource has failed to move into its Forbidden Operating Region as instructed by the CAISO in a Dispatch Instruction, the ISO's systems will set the resource's DOT and initial conditions outside the boundary of the Forbidden Operating Region from which the resource was intended to enter the Forbidden Operating Region. In other words, if a resource is dispatched into a Forbidden Operating Region from above its upper boundary, and the RTM functionality identifies that the resource has failed to move into its Forbidden Operating Region, the resource's DOT and initial conditions will be set outside the upper boundary. Conversely, if a resource is dispatched into a Forbidden Operating Region from below its lower boundary, and the RTM functionality identifies that the resource has failed to move into its Forbidden Operating Region, the resource's DOT and initial conditions will be set outside the lower boundary. As such, the resource will be identified as outside of it's FOR and available to for economic dispatch by the RTM.

7.3   CAISO Activities

The principle activities that CAISO performs are described in the following subsections.

7.3.1   Accept Real-Time Market Inputs

This section lists the inputs that are common to the Real-Time processes. The inputs that are submitted for the DAM that are also used in the Real-Time process are not repeated here. Note that Real-Time Bids can be submitted after the DAM results are published.

7.3.1.1   Energy Limits & Energy Quota Calculation

As per Section 5.1.1.2.2 of Market Instruments BPM, Daily Energy Limits (a maximum and a minimum) Minimum Daily Energy limits are not enforced for Generating Resources. These are an optional component submitted by SCs in their Day-Ahead bids, and if submitted and validated, are enforced in all DAM applications. The enforcement of daily Energy Limits is straightforward in these applications because the Time Horizon is a Trading Day. Energy Limits are also enforced in the RTM applications to assure that the Unit Commitment and Dispatch these applications perform do not violate at the end of the Trading Day the daily Energy Limits that are enforced in the Schedules produced in the DAM. CAISO is committed to honoring Energy Limit constraints unless doing so would violate reliability of the grid.

This section describes the methodology employed in RTM for deriving Energy Limits for the relevant Time Horizon so that: (a) the daily Energy Limits are not violated at the end of each Trading Day and (b) there is sufficient room between the minimum and maximum Energy Limits for optimal Dispatch.

If the Time Horizon spans a Trading Day boundary, the Energy Limits are derived in parts for each Trading Day applying the following general methodology using the data and variables applicable to the relevant Trading Day for each resource. The following concepts are used in the section:

- ➤ **Scheduled Energy Quota** – To derive a maximum Energy Limit, the scheduled Energy quota is calculated as the scheduled Energy out of the higher of the IFM or RUC schedule, from the start of the Trading Day to the end of the RTM Time Horizon. To derive a minimum Energy Limit, the scheduled Energy quota is calculated as the scheduled Energy out of the lower of the IFM or RUC schedule[30], from the start of the

---

[30] Except for IFM Energy or Minimum Load Energy, a RUC schedule is not an Energy schedule.

Trading Day to the end of the RTM Time Horizon. The scheduled Energy quota may be negative for a minimum Energy Limit in the case of a Pumped-Storage Hydro[31] Unit scheduled to pump.

➢ **Unused Energy Quota** – The unused Energy quota is a pro rata allocation of unused daily Energy (daily Energy Limit minus scheduled Energy over the Trading Day) from the start of the Trading Day to the end of the RTM Time Horizon. The unused Energy quota may be negative for a minimum Energy Limit in the case of a Pumped-Storage Hydro Unit.

➢ **Dispatched Energy Quota** – The dispatched Energy quota is the total Energy dispatched in RTM from the start of the Trading Day to the start of the RTM Time Horizon. The dispatched Energy quota may be negative in the case of a Pumped-Storage Hydro Unit dispatched in the pumping mode.

➢ **Energy Limit** – The Energy Limit for the RTM Time Horizon is calculated as the sum of the scheduled Energy quota and the unused Energy quota from the start of the Trading Day to the end of the RTM Time Horizon, reduced by the dispatched Energy quota from the start of the Trading Day to the start of the RTM Time Horizon. The minimum Energy Limit may be negative in the case of a Pumped-Storage Hydro Unit.

Energy Limits are enforced in the RTM applications as soft constraints, i.e., with lower penalty costs than other constraints, such as network constraints and Exceptional Dispatches. Exceptional Dispatches, in particular, and also Outages and derates may result in Energy Limit violations.

The described methodology enforces the daily Energy Limits as a dynamically adjusted rolling average over the course of a Trading Day, providing room for optimal refinement of the DAM Schedules in Real-Time. Aside from the effect of other binding constraints that may conflict with the Energy Limit constraints, the methodology assures a feasible outcome, but only when Dispatch Instructions are followed accurately, and neither AGC actions, contingencies nor Exceptional Dispatches cause Energy Limit violations, since the formulation involves only Instructed Imbalance Energy.

Consequently, Energy Limits may be violated due to the regulating action of units on Regulation and due to Uninstructed Deviations driving the Dispatch Instructions via the State Estimator feedback. The method attempts to recover any Energy outside the rolling average limits over

---

[31] Minimum Energy Limit for a Pump-Storage Hydro resource reflect the maximum of pumping energy that can be consumed.

the course of a Trading Day, however, this may not be possible if Uninstructed Deviations persist.

This means that if a resource deviates and causes the Energy Limits to exceed the rolling average Energy Limits but not the total Energy Limit for the day, then the solution attempts to reduce the Dispatch of the resource for future Dispatches in order to recover or conserve the Energy Limits in the future. If the total Energy Limit has been hit then the recovery is not possible.

7.3.1.2   Ancillary Service Award Allocation on Energy Bids

Refer to the description given in Section 4.2.2 of this BPM.

7.3.1.3   Resource Capacity Constraints

RTM optimally commits and dispatches resources to balance Supply and Demand subject to resource and network constraints. Capacity constraints limit the Energy Dispatch and the AS Awards to the available resource capacity or the applicable MSG Configuration's capacity for a Multi-Stage Generating Resource as follows:

- ➢ On-line resource not scheduled for Regulation:
    - ▪ The Energy Dispatch must be greater than or equal to the lower operating limit.

    - ▪ The sum of the Energy Dispatch and the Non-Spinning and Spinning Reserve Awards must be less than or equal to the lower of the upper economic limit or the upper operating limit.

- ➢ On-line resource scheduled for Regulation:
    - ▪ The Energy Dispatch minus the Regulation Down Award must be greater than or equal to the higher of the lower regulating limit or the lower operating limit.

    - ▪ The sum of the Energy Dispatch and the Non-Spinning and Spinning Reserve Awards must be less than or equal to the upper economic limit.

    - ▪ The sum of the Energy Dispatch and the Non-Spinning, Spinning, and Regulation Up Awards must be less than or equal to the lower of the upper regulating limit or the upper operating limit.

- ➢ Off-line Fast Start Unit:
    - ▪ The Energy Dispatch must be zero.

- The Non-Spinning Reserve Award must be less than or equal to the lower of the upper economic limit or the upper operating limit. No energy Bid is required if the Non-Spinning Reserve Award is less than or equal to the Minimum Load.

Where:

- The lower operating limit is the resource Minimum Load adjusted by any applicable overrates[32]

- The upper operating limit is the resource maximum capacity adjusted by any applicable derates

- The upper economic limit is the highest operating level in the resource Energy Bid

- The lower regulating limit is the lowest operating level below which the resource cannot regulate

- The upper regulating limit is the highest operating level above which the resource cannot regulate

Further details on Upper and lower operating limits are given in Section 4.2.3, Ancillary Service Award Allocation of Energy Bids, and Exhibit 6-4, Capacity Available for RUC.

For resources on regulation with two regulating ranges, the regulating range for the current operating hour is obtained from EMS. The regulating range for the following operating hours is determined based on which range can accommodate Day-Ahead Regulation Down Award immediately below the Day-Ahead Schedule, and a simultaneous dispatch of Day-Ahead Regulation Up, Spinning Reserve, and Non-Spinning Reserve Awards, above the Day-Ahead Schedule. In the case where both regulation ranges can accommodate all Day-Ahead AS Awards, the lower regulation range that contains the Day-Ahead Schedule will be selected. If an Exceptional Dispatch would take a regulating unit outside of the EMS regulation range (for the current operating hour) or the selected regulating range (for the following operating hours), RTM will assume that the unit is taken off regulation.

The AS Awards include the relevant DAM AS Awards, any qualified AS self-provision, and the selected incremental AS Awards in FMM. The Energy Dispatch and the selected AS Bid are decision variables, optimally determined to minimize the Energy and AS procurement cost over the entire Time Horizon. When making a decision to shut down a resource in RTM, minimum

---

[32] 'An "overrate" is the opposite of a "derate": an "overrate" restricts a resource's operating range above its lower operating limit, in contrast to a "derate" that restricts its operating range below its upper operating range.

load costs that arise as a result having to maintain a resource online to allow a resource to meet its day-ahead binding commitment while ensuring the resource does not violate the resources minimum down time may be considered prior to time the resources minimum down time becomes binding. It is important to note that Spinning and Non-Spinning Reserve self-provision requires an Energy Bid for qualification in the RTM, unlike the DAM. Regulation Up Bids can be selected irrespective of the presence of an Energy Bid.

Real-Time AS Awards awarded in FMM are settled at the relevant ASMP. When resource capacity constraints are binding at the optimal solution, the LMP reflects the opportunity cost of the resource capacity that is reserved from dispatching Energy in order to provide AS.

7.3.2   Close Real-Time Market

The Real-Time Market is closed at 75 minutes before the beginning of the Trading Hour.

7.3.3   Execute Real-Time Applications

The following Real-Time applications are executed by CAISO after bidding for the market closes:

- ➢ MPM (every 15 minutes) for RTUC, every 5 minutes for RTD)
- ➢ RTUC/FMM (every 15-min)– #1 incorporates HASP
- ➢ STUC (hourly)
- ➢ RTED (every 5 minutes)
- ➢ RTCD (on demand)
- ➢ RTMD (on demand)

The table shown by Exhibit 7-3 summarizes the execution of these applications.

Exhibit 7-3: Real-Time Applications

Application	Periodicity	Interval	Time Horizon	Task
RTUC/FMM	15-min Beginning at midpoint of each 15-min period	15-min	105-60 min	Unit Commitment for the 105-60 min Time Horizon. 15-min AS Awards for the second 15-min interval of the Time Horizon.

Application	Periodicity	Interval	Time Horizon	Task
MPM	15-min Beginning at midpoint of each 15-min period 5-min Beginning at midpoint of each 5-min period	15-min 5-min	105 min 55-65 min	Market Power Mitigation for RTM Bids submitted at T–75' for the Trading Hour from T to T+60'.
HASP See Note 1	Hourly	15-min	105 min,	Hourly pre-dispatch for hourly block Bid System Resources for the Trading Hour from T to T+60'. Advisory 15-min dispatch for all other resources for the Trading Hour from T to T+60'. Advisory 15-min AS Awards for resources for the Trading Hour from T to T+60'. Binding hourly AS Awards for Non-Dynamic System Resources for the Trading Hour from T to T+60'.
STUC	Hourly Beginning at $T – 52.5'$	15-min	270 min	Unit Commitment for the Time Horizon from T–30' to T+240'.
RTED	5-min Beginning at midpoint of each 5-min period	5-min	55-65 min	5-min Dispatch for Dynamic System Resources and Generating Units for the first 5-min interval of the Time Horizon.
RTMD	On demand	5-min	5-min	5-min Dispatch for Dynamic System Resources and Generating Units.
RTCD	On demand	10-min	10-min	10-min Dispatch for Dynamic System Resources and Generating Units. 10-min Dispatch for Non-Dynamic System Resources AS Energy

Note 1: The HASP functionality is embedded in the RTUC application; the first of the four RTUC runs performs the HASP function.

7.3.4   Publish Real-Time Market Reports to Scheduling Coordinators

The following is a summary of the Real-Time Market reports available to SCs for online viewing:

➢ **Real-Time MPM Results** – Information about the mitigated Bid that is used if the original Bid is modified in the RTM.

➢ HASP hourly Energy Dispatch and AS awards for Non-Dynamic System Resources that have submitted Hourly Block Bids.

➢ HASP 15-min advisory Energy Dispatch and Ancillary Services Awards for all other resources.

➢ FMM 15-min Energy and Ancillary Services Awards, both for the binding interval and the advisory intervals in the RTUC time horizon.

➢ **Hourly Inter-SC Trades** – Inter-SC Trade Schedules for both Trades at Aggregated Pricing Nodes and physical trades, for both Energy and Ancillary Services Obligation, as a result of the HASP.

Refer to the *BPM for Market Instruments* for the detailed contents of these reports.

7.4   MPM for Real-Time

This section is based on CAISO Tariff Sections 34.1.5 (Mitigating the Bid Sets Used in the RTM Optimization Processes). For a given Trading Hour, MPM is performed separately in the HASP process, and in the RTUC processes.

After the Market Close of RTM, after CAISO validates the Bids pursuant to CAISO Tariff Section 30.7, and prior to running the HASP optimization, the CAISO conducts the MPM process, the results of which are utilized in the HASP optimization. Although the RTUC MPM process is separate, the mitigation results from HASP are used as inputs to the advisory intervals of the next RTUC run as discussed below.

In RTUC, the MPM process performs a DCPA for the financially binding interval of the RTUC run. For a given hour, a Bid that is not mitigated in one RTUC run may be mitigated in a subsequent RTUC run for the same hour. Once a resource's bid is mitigated in a RTUC run, the mitigated Bid applies for the remainder of the applicable hour and cannot be unmitigated by subsequent RTUC runs. However, a Bid may be mitigated further to a lower price in a subsequent RTUC run for the applicable hour, but never below the Default Energy Bid.

Any bids mitigated in RTUC, or mitigated further in a subsequent RTUC run, will be used by the corresponding RTD intervals (for example, mitigation for interval:00-:15 applies to RTD intervals :00-:05, :05-:10, and :10-:15) .

For RTD, the MPM process starts with the first advisory interval after the binding interval of each RTD run. RTD performs a DCPA on this interval, the results of which are used in the binding interval of the following RTD run. Once a resource's bid is mitigated in a RTD run, the mitigated Bid applies for the remainder of the RTD intervals corresponding to the same RTUC interval. Bids cannot be unmitigated by subsequent RTD runs in the same 15-minute RTUC interval. However, a Bid may be further mitigated in a subsequent RTD interval, but never below the Default Energy Bid.

The features of the Real-Time MPM are as follows:

For HASP and RTUC:

➢ The Time Horizon for MPM in RTM is 60 minutes (i.e., from T to T+60').

➢ The CAISO Forecast of CAISO Demand time resolution in RTM is 15 minutes.

➢ Each market interval for MPM in RTM is 15 minutes.

➢ Bids on behalf of dispatch able pumps, Non-Generator Resources, Participating Load, Demand Response Resources and other forms of bid in demand are considered in the MPM process as part of the power balance equation; however, the bids are not subject to mitigation.

For RTD:

➢ The CAISO Forecast of CAISO Demand time resolution in RTD is 5 minutes.

➢ Each market interval for MPM in RTD is 5 minutes.

➢ Bids on behalf of dispatch able pumps, Non-Generator Resources, Participating Load, Demand Response Resources and other forms of bid in demand are considered in the MPM process as part of the power balance equation; however, the bids are not subject to mitigation.

For HASP only:

> ➢ The HASP MPM in RTM occurs immediately after the RTM close of bidding at 75' before the Trading Hour.

> ➢ The Energy Bid mitigation in HASP is first performed on a 15-minute basis; and then the four 15-minute mitigated Bids for each resource are synthesized to produce the hourly mitigated Bid as follows:
>
> A single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level.
>
> For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a single RMR Proxy Bid for the entire Trading Hour is calculated using the same methodology described as for non-RMR Units. The RMR Proxy Bid will be utilized in both the HASP optimization and all RTM processes for the Trading Hour.

> ➢ If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process.

> ➢ For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP.

Refer to section 6.56.56.5 for details on the MPM process.

7.4.1   Example

The following steps describe the business process and data flows for the HASP and RTUC mitigation using an example starting from a HASP run.

HASP run time horizon: 00:15 – 2:00;

The periodic run that includes HASP has seven 15-min. intervals, three of which are before the HASP hour. The first three intervals before the HASP hour depend on mitigation results from previous RTUC runs (and even the previous hour's HASP) that were applicable for that hour. In

other words, the bids used for the current hour (00:15-01:00) could have been mitigated by the previous RTUC mitigation already.

Assumptions:

Resource A:
- For 00:15 – 01:00, the unit was mitigated by the previous RTUC mitigation run. Its mitigated bid is $40 and SIBR clean bid was $140.
- For 01:00 – 02:00, its SIBR clean bid is $145;

Resource B:
- For 00:15 – 01:00, the unit's SIBR clean bid is $60 (not mitigated by previous RTUC mitigation so it is the clean bid);
- For 01:00 – 02:00, its SIBR clean bid is $65;

Each HASP run is separated into two steps: (1.1) pre-HASP mitigation; (1.2) HASP SCUC;

Step 1.1. Pre-HASP mitigation

For each HASP trading hour, the pre-HASP mitigation shall be performed to obtain an hourly bid curve for each generation resource, mitigated or not;

Example after step 1.1,

Resource A's bid for 01:00 – 02:00 is mitigated from $145 to $45 (using the lowest bid curve segments); Resource B's bid for 01:00 – 02:00 is $65;

Effectively for 01:00 – 02:00, Resource A is mitigated and resource B is not.

Inputs to step 1.2 are as follows:

- Resource A's bid for 00:15 – 01:00 is $40;
- Resource A's bid for 01:00 – 02:00 is $45;
- Resource B's bid for 00:15 – 01:00 is $60;
- Resource B's bid for 01:00 – 02:00 is $65;

Pre-HASP mitigation only mitigates bids for the HASP trading hour. The bid set will be used in HASP SCUC in step 1.2.

Step 1.2. HASP SCUC

HASP SCUC uses the bid set from pre-HASP mitigation to perform the unit commitment, AS procurement for internal generators, AND the intertie scheduling and AS imports for the HASP binding hour.

RTUC mitigation

Each RTUC run contains an in-line DCPA and MPM process that determines mitigation for the financially binding interval of that RTUC run. Mitigation in a given RTUC run can also come from previous RTUC intervals of the same trading hour, if the given run is not the first in the hour. Any mitigation determined to be necessary in a given RTUC run will also be carried through the subsequent RTUC runs for that hour, and will be passed to the RTD runs for the rest of the hour.

RTD mitigation

For each RTD run, the results of the first advisory interval after the financially binding interval are passed to the LMPM-DCPA module. The LMPM-DCPA module determines whether binding paths are competitive, which resources are potentially eligible for mitigation, which bids will be mitigated, and to what price those bids will be mitigated. The results are passed to the next RTD run, where they are used for the financially binding interval for that run. Bids that are mitigated by the RTD mitigation will remain mitigated for the subsequent RTD intervals that correspond to the same RTUC interval as the advisory interval where the mitigation was first determined to be necessary. For advisory intervals that correspond to the first RTD interval in an RTUC interval, the RTUC mitigated bids are used to evaluate competitiveness. For subsequent RTD intervals, the final mitigated bid set from the previous RTD interval is used.

7.5   Hour-Ahead Scheduling Process

This section is based on CAISO Tariff Section 34.2, Hour-Ahead Scheduling Process (HASP).

HASP is the hour-ahead scheduling process during Real-Time. The HASP functionality is included in a special hourly run of RTUC. RTUC utilizes a SCUC optimization and runs every 15 minutes, as described in Section 34 of the CAISO Tariff and Section 7.6 of this BPM. This section describes the special features of the specific hourly HASP run of RTUC.

HASP enables the CAISO to issue hourly pre-dispatch instructions to Non-Dynamic System Resources that submit hourly block Bids to HASP along with HASP Advisory Schedules for Energy and AS Awards for all other participants in the RTM.   The hourly pre-dispatch instructions consist of HASP Block Intertie Schedules for Energy and Ancillary Services and

HASP Advisory Schedules for Economic Hourly Block Bids with Intra-Hour Option that may change for economic reasons at most once in the Trading Hour.

7.5.1   HASP Inputs

This section describes the inputs that are specific to HASP, excluding those inputs that are common to all the Real-Time processes.

7.5.1.1   RTM-CAS Interface

Control Area Scheduler (CAS) is the application where all System Resource Schedules, and Dispatch Instructions are logged. HASP Energy Schedules and Exceptional Dispatch Instructions are first sent by RTM to ADS and CAS, and then confirmed by CAS for use in future RTM runs. Because System Resource Dispatch needs to go through the Balancing Authority Area checkout process, sending these Dispatch Instructions to ADS is not sufficient. The Dispatch is confirmed by the CAISO Operators and is entered into CAS. In this case the resulting dispatch may be different from the RTM Dispatch instruction. The confirmed Dispatch is communicated back from CAS to the RTM to be used in the next Dispatch calculation. In other words, CAS overrides ADS once the Dispatch has been entered into CAS and communicated back to RTM.

The actual intertie flows, obtained from telemetry, do not provide information about individual System Resource Dispatch; this information is obtained from CAS. Any difference between the net CAS Dispatch and the telemetered actual flow on a given intertie is attributed to Loop Flow and is factored into the calculation of Loop Flow compensating injections prior to the optimal Dispatch calculation.

7.5.1.2   Self-Schedules in HASP

This section is based on CAISO Tariff Section 34.2.2, Treatment of Self-Schedules in HASP.

SCs may submit Self-Schedules for Supply of Energy to HASP. SCs may not submit Self-Schedules for CAISO Demand to HASP.

The HASP optimization clears Bids, including Self-Schedules, from Non-Dynamic System Resources that submit block Bids while preserving all priorities in this process consistent with Section 31.4 of the CAISO Tariff. The HASP optimization does not adjust submitted Self-Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Effective Economic Bids, in which case the HASP performs adjustments to Non-priced Quantities.

CAISO uses the CAISO Forecast of CAISO Demand and distributes this Demand Forecast based on the applicable set of Load Distribution Factors.

The MWh quantities of Self-Scheduled Supply that clear in HASP constitute a feasible Dispatch for the RTM at the time HASP is run, but HASP results do not constitute a final Schedule for resources other than Non-Dynamic System Resources that submit block Bids because these resources may be adjusted in the FMM or RTED if necessary to manage Congestion and clear Supply and Demand.

Self-Schedules submitted for resources other than Non-Dynamic System Resources that submit block Bids that clear in HASP are issued HASP Advisory Schedules which are considered as Self-Schedules or Self-Provision in each of the four FMM intervals. Scheduling Coordinators representing VER resources may submit Self-Schedules in HASP based on the most current Energy forecast based on CAISO's or their own submitted forecast, depending on their election as recorded in the Master File. The HASP produces HASP Advisory Schedules for each of the four fifteen-minute intervals for FMM Economic Bids cleared in HASP, which can vary from the schedules cleared in the Fifteen Minute Market.

7.5.2   HASP Constraints & Objectives

This section is based on CAISO Tariff Section 34.2.1, The HASP Optimization.

After the HASP and RTM Market Close for the relevant Trading Hour, and the Bids have been validated the HASP optimization determines feasible HASP Advisory Schedules and Ancillary Service awards for most resources for each 15-minute interval of the Trading Hour, as well as hourly HASP Block Intertie Schedules, including binding energy and AS awards, from Non-Dynamic System Resources that submit hourly block Bids for that Trading Hour. For these bids, the optimization produces a set of constant schedules for the four 15-minute intervals of the Trading Hour, honoring system conditions and economic results over the hour.

HASP, like the other runs of RTUC, utilizes the same SCUC optimization and FNM as IFM, with FNM updated to reflect changes in system conditions as appropriate, to ensure that HASP Block Intertie Schedules are feasible.

Instead of clearing against Demand Bids as in IFM, HASP clears Supply against the CAISO Forecast of CAISO Demand plus submitted Export Bids to the extent the Export Bids are selected in the MPM process. The HASP optimization also factors in forecasted unscheduled flow at the Scheduling Points. Note, self-schedules for export Resources will be given the same scheduling priority as internal price taker demand when validated to be supported by non-RA capacity, and will be given a lower price taker priority when supported by RA capacity. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services.

7.5.3   HASP Outputs

HASP outputs are described in the following subsections.

7.5.3.1   HASP Prices

This section is based on CAISO Tariff Section 34.2.1, The HASP Optimization..

7.5.3.2   HASP produces advisory 15-minute LMPs for the four 15-minute intervals for the applicable Trading Hour. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services. Bids accepted through the HASP are settled based on FMM Schedules and Awards and FMM LMPs and ASMPs HASP Binding Schedules

HASP produces binding Energy and Ancillary Services schedules only for Non-Dynamic System Resources that submit hourly block Bids for the Trading Hour. These schedules are known as HASP Block Intertie Schedules.   Although operationally binding, the awarded Energy and Ancillary Services schedules will be settled at prices generated by FMM.

7.5.3.3   HASP Advisory Schedules

Exhibit 7-4 illustrates the advisory Schedule for a Generating Unit for a particular time increment of the HASP. Note: the Energy Schedules for Generating Units and Dynamic Resources are advisory for all intervals in the HASP run, as well as for all intervals of the other three runs of FMM. The Ancillary Services Award for Generating Units and Dynamic Resources is advisory for all intervals but the first interval in all RTUC runs, including HASP.

Exhibit 7-4: Advisory Schedule from HASP
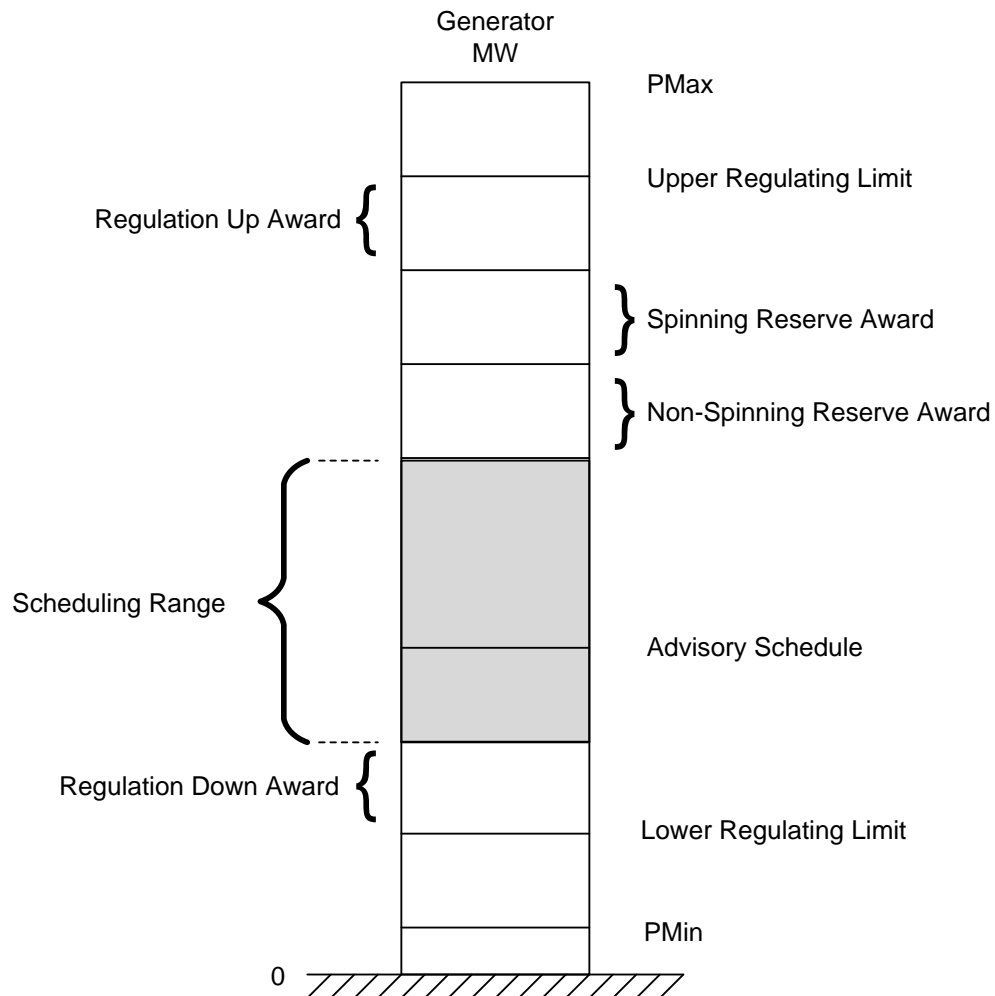
7.6 Real-Time Unit Commitment and Fifteen-Minute Market

This section is based on CAISO Tariff Section 34.3, Real-Time Unit Commitment, and 34.4, Fifteen Minute Market4.

The RTUC process uses SCUC (see Attachment A.1, Security Constrained Unit Commitment) and is run every 15 minutes to:

➢ Make commitment decisions for Fast Start and Short-Start Units that are able to start within the Time Horizon of the RTUC process. For Multi-Stage Generating Resources, it also includes the transition decisions for the Multi-Stage Generating Resources that are able to start within the Time Horizon of the RTUC process

➢ Determine financially binding FMM Schedules and corresponding LMPs, including System Resources

➢ Procure required additional AS and re-calculate ASMP used for settling procured AS capacity for the next 15-minute Real-Time AS interval

➢ Determine LAP LMPs for use in settling Demand

➢ Process forecasts and limits for VERs

RTUC is run four times an hour (see Exhibit 7-1), at the following times for the following Time Horizons:

1) Starting at approximately 67.5 minutes prior to the Trading Hour for TH-30 minutes to TH+60 minutes; this includes the HASP run

2) Starting at approximately 52.5 minutes prior to the Trading Hour for TH-15 minutes to TH+240 minutes; this is the STUC run

3) Starting at approximately 37.5 minutes prior to the Trading Hour for TH minutes to TH+60 minutes

4) Starting at approximately 22.5 minutes prior to the Trading Hour for TH+15 to TH+60 minutes

Where TH is the beginning of the Trading Hour.

7.6.1   Real-Time Unit Commitment Inputs

There are no special inputs to the RTUC beyond those described previously from the close of the Real-Time Market at 75 minutes before the start of the Trading Hour.

7.6.2   Real-Time Ancillary Services Procurement

To the extent possible, the CAISO attempts to procure 100 percent of Ancillary Services in the Day-Ahead Market. CAISO procures AS in Real-Time using the FMM, and for Non-Dynamic System Resources with hourly block Bids only, the HASP process, as needed to replenish Operating Reserves or Regulation, should the AS procured in the forward markets be called in Real-Time or become unavailable due to Outages or derates. The CAISO procures AS in the Real-Time as needed to satisfy the NERC requirements. The resources committed by the CAISO in Real-Time to provide AS are eligible for Start-Up and Minimum Load Cost compensation through the BCR process as specified in Section 11.8 of the CAISO Tariff.

AS procured in RT are paid based on the ASMP. See Section 4.4 for details of the ASMP payment.

For purposes of the Real-Time AS procurement, all resources certified to provide Spinning or Non-Spinning Reserves (Operating Reserves) for which an Energy Bid has been submitted or an Energy Bid has been generated by SIBR, are deemed available to CAISO to provide Operating Reserves. Real-Time procurement and pricing of Operating Reserves is performed using dynamic co-optimization of Energy and Spinning and Non-Spinning Reserve. If the Scheduling Coordinator does not submit a Bid for Operating Reserves but has submitted an Energy Bid, the CAISO inserts a Default AS Bid Price on their behalf for all Operating Reserve to allow the CAISO to procure either Energy or Operating Reserve up to the maximum bid-in level as represented by the Energy Bid. This is irrespective of whether that resource has been awarded an IFM AS award. In any case, any Energy Bid associated with an Ancillary Services Bid for the same Resource ID of a Non-Dynamic System Resource, the ISO will not utilize the Energy Bid in the clearing the RTM to Dispatch Energy, unless the Resource ID is also awarded Ancillary Services for that interval.

For Regulation, all resources certified and capable of providing Regulation that have been awarded Regulation in Day-Ahead Market or have submitted a Bid to provide Regulation in the Real-Time Market shall also submit applicable Regulation Bids up to their certified value. Otherwise, SIBR will create a Default AS Bid Price for the remaining certified quantity. (Section 34.2.2 of the CAISO Tariff.)

Additional Ancillary Services are procured in Real-Time only from resources that are certified to provide these services.

RTM evaluates AS needs and procures any shortfall using the RTUC application (on a 15-minute basis). Real-Time AS requirements are calculated within RTM based on system/regional requirements determined by WECC and Real-Time operating conditions.

Resources committed by the CAISO in Real-Time to provide additional Spinning Reserve and offline Fast-Start Units providing additional Non-Spinning Reserve are both eligible for Bid Cost Recovery. Additionally, the Real-Time procurement of AS does not result in a withdrawal of any earlier RUC Availability Payments for RUC Awards, i.e., RUC Capacity procured in the DAM can be used for AS procurement in RTM. Dispatched Energy from resources selected to provide AS in Real-Time are settled as Instructed Imbalance Energy.

Real-Time Regulation procurement may be necessary to recover regulating margin lost due to Outages or derates. Regulation procured in RTM is paid the 15-minute ASMP at the location of

the resource. SCUC and SCED use the revised Regulation ranges in allocating AS to the Energy Bid in subsequent runs, and the Regulation deficiency report is revised accordingly.

7.6.2.1   Real-Time Ancillary Services Procurement in HASP

The HASP optimization will consider the optimal mix of Ancillary Services and Energy from System Resources and from Generating Units, but only the Ancillary Service from Non-Dynamic System Resources with hourly block Bids awarded in HASP are binding. These binding Ancillary Services Awards are for the full Trading Hour for which the given HASP run applies. All other resources designated in the HASP to provide Ancillary Services for the same Trading Hour receive non-binding advisory Ancillary Services awards because the CAISO will re-optimize the use of these resources to provide Ancillary Services in the FMM.

All Operating Reserves procured in HASP are Contingency Only Operating Reserves. Scheduling Coordinators submitting Ancillary Services Bids for Non-Dynamic System Resources in the HASP must also submit an Energy Bid under the same Resource ID for the associated Ancillary Services Bid. For these Non-Dynamic System Resources, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not Schedule Energy in HASP in addition to the relevant Day-Ahead Schedule or Real-Time self-schedule from the Energy Bid provided under the same Resource ID as the Ancillary Services Bid.

7.6.3   Real-Time Unit Commitment Constraints & Objectives

The RTUC uses the SCUC co-optimization engine to minimize costs as reflected in the Bids subject to capacity and inter-temporal resource constraints and using the FNM.

7.6.3.1   Treatment of Generating Resources

Generating Resources that have economic bids will be economically dispatched by the optimization engine and the resulting dispatch is binding in FMM. If the resource is a VER, then for each 15-minute interval an upper dispatch limit will be set to the average of the VER's three forecasts for the corresponding 5-minute intervals. Effectively this means that a VER's bids will be limited or extended to a dynamic upper dispatch limit for each 15-minute interval in the time horizon.

For self-scheduled VERs, FMM calculates a self-schedule for each 15-minute interval in the time horizon by taking an average of the three forecasts for the corresponding 5-minute intervals (or latest State Estimator reading if forecast unavailable). The resulting set of self-schedules is treated like any other self-scheduled resource.

The RTUC dispatches will be settled at the FMM price. However the dispatch will be subject to further modification in RTD.

7.6.3.2   Treatment of System Resources

System Resource bids have several options of bidding in Real-Time. FMM optimizes these resources differently depending on the bidding option chosen. Treatment of Energy and Ancillary Services is the same.

> ➢ Self-Scheduled Hourly Block – Resource dispatch from HASP will be treated as a self-schedule (or Ancillary Services Self-Provision) and will be treated like any other self-scheduled resource. Variable Energy Resource Self-Schedule – Each VER resource has a series of 5-minute forecasts of output. FMM calculates a self-schedule for each 15-minute interval in the time horizon by taking an average of the three forecasts for the corresponding 5-minute intervals (or latest State Estimator reading if forecast unavailable). The resulting set of self-schedules is treated like any other self-scheduled resource.
> ➢ Economic Hourly Block Bid – Resource dispatch from HASP will be treated as a self-schedule (or Ancillary Services Self-Provision) and will be treated like any other self-scheduled resource.
> ➢ Economic Hourly Block Bid with Intra-Hour Option – Resource dispatch from HASP will initially be treated by FMM as an advisory schedule, i.e. the resource may be economically dispatched by the optimization engine and the resulting dispatch is binding, with the caveat that the resource dispatch must be economic for the binding and any remaining advisory intervals of the Trading Hour, i.e. as if they were constant schedules similar to HASP. If the resulting dispatch is different than the HASP dispatch, then for any subsequent FMM runs in the Trading Hour the previous FMM dispatch will be treated as a self-schedule and will be treated like any other self-scheduled resource.
> ➢ Economic Bid for a Schedule in the RTM – The resource may be economically dispatched by the optimization engine and the resulting dispatch is binding. If the resource is a VER, then for each 15-minute interval an upper dispatch limit will be set to the average of the VER's three forecasts for the corresponding 5-minute intervals.
> ➢ Dynamic transfer - The resource is treated the same as a Generating Resource by FMM.

7.6.4   Real-Time Unit Commitment Outputs

The resulting RTUC-based commitment instructions are the final decisions regarding resource commitments to adjust Day-Ahead Schedules. Other information is also published. Both the binding awards and information from the first interval and the advisory results from the remaining intervals in the FMM time horizon are available to SCs.

- ➢ **Ancillary Service Awards** – generated by FMM and as modified by the CAISO Operator are sent to ADS and CMRI every fifteen minutes for dispatchable resources. The AS Award separately identifies the Day-Ahead Award, the Real-Time qualified self-provision, and the Real-Time AS Award. For Spinning and Non-Spinning Reserve, the Contingency Dispatch indicator is also reported. In any given interval where the software solution does not converge, the CAISO will issue binding Ancillary Services Awards and advisory data based on the advisory results produced by the previous successful RTUC run for the applicable interval. In such cases, all 15-minute data including Ancillary Services Awards, prices, and other supporting data are copied from the advisory results of the previous run.

- ➢ **Energy Schedules** – generated by FMM and as modified by the CAISO Operator are sent to ADS and CMRI every fifteen minutes for both binding and advisory intervals. In any given interval where the software solution does not converge, the CAISO will issue energy schedules based on the advisory results produced by the previous successful FMM run for the applicable interval. In such cases, all 15-minute data including Energy Schedules, prices, and other supporting data are copied from the advisory results of the previous run.

- ➢ **Commitment Instructions** – generated by RTUC and as modified by the CAISO Operator are sent to ADS every fifteen minutes from RTUC. In any given interval where the software solution does not converge, the CAISO will issue binding commitment instructions based on advisory commitment instructions obtained from the previous successful RTUC run, if the previous advisory instructions become binding in the current time frame based on the associated startup time, shutdown time or transition times as further described in Tariff Section 34.4 and 34.5. When determined binding, the commitment instructions and all information associated with those instructions of the previous run are copied and carried over into the current run horizon.

- ➢ **VER forecast** – The 15-minute resource specific forecast used in FMM will be reported to SCs.

7.6.5   Real-Time Unit Commitment Pricing

The RTUC includes a pricing run to calculate FMM LMPs and ASMPs. FMM produces 15-minute LMPs for the settlement of Supply and Demand. FMM Schedules are settled in accordance with Tariff Section 11.5.

FMM also produces 15-minute ASMPs for any Operating Reserves Awarded in FMM. These ASMPs will correspond to the Ancillary Services Awards procured for the applicable FMM interval.

Both the financially binding prices from the first interval and the advisory prices from the remaining intervals in the FMM time horizon are published.

7.7   Short-Term Unit Commitment

This section is based on CAISO Tariff Section 34.6, Short-Term Unit Commitment.

At the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed, CAISO performs an approximately five-hour STUC run using SCUC and the CAISO Forecast of CAISO Demand to commit Medium Start Units and Short-Start Units with Start-Up Times greater than the Time Horizon covered by the FMM.

The Time Horizon (see Exhibit 7-1) for the STUC optimization run extends three hours beyond the Trading Hour for which the FMM optimization was run, and replicates the Bids used in that Trading Hour for these additional hours.

CAISO replicates Bids each time the hourly STUC is run, to utilize the most recently available Bids. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run as a result of the Start-Up Time of the resource.

A Start-Up Instruction produced by STUC is considered advisory if it is not binding, i.e., when the resource can achieve its target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run based on its Start-Up Time. A Start-Up Instruction produced by STUC that results in a change in Commitment Status is issued after review and acceptance of the Start-Up Instruction by the CAISO Operator, in accordance with Section 6.3 of the CAISO Tariff.

The STUC only de-commits a resource to the extent that resource's physical characteristics allow it to be brought back online at the end of the Time Horizon. This requirement is needed because RTUC is unaware of future commitments that a resource may have beyond the Time Horizon.

STUC does not produce prices for Settlement. The STUC process only commits units needed for meeting Real Time imbalances. To the extent a unit is committed via STUC, a Start-Up instruction is provided to that resource (via ADS). Whether or not the resource is eligible for Start Up and Minimum Load Bid Cost Recovery is determined through a series of calculations described in the *BPM for Settlement and Billing, Section 12*.

7.7.1   Short-Term Unit Commitment Inputs

The following are special inputs to STUC that are in addition to the common inputs described earlier in this BPM:

➢ The STUC uses a short-term Load forecast (15-minute intervals over a five-hour Time Horizon

7.7.2   Short-Term Unit Commitment Constraints & Objectives

The STUC application uses the SCUC engine described in Attachment A, Market Optimization. STUC enforces the same constraints that are present in all RTUC runs.

The STUC produces a Unit Commitment solution for every 15-minute interval within the Time Horizon.

7.7.3   Short-Term Unit Commitment Outputs

As described in CAISO Tariff Section 34.6, The STUC outputs include the following instructions:

➢ **Binding Commitment Instructions** – Determined by RTUC, including STUC, are sent to ADS every fifteen minutes.

7.8   Real-Time Economic Dispatch

This section is based on CAISO Tariff Section 34.3.1, Real-Time Economic Dispatch, Section 34.5, General Dispatch Principles, and 34.16.3.1, Regulation.

The RTED mode of operation normally runs every 5 minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces a Dispatch Instruction for Energy for the next Dispatch Interval and advisory Dispatch Instructions for as many as 12 future Dispatch Intervals over the RTD optimization Time-Horizon of up to 65 minutes.

After being reviewed by the CAISO Operator for correctness and reliability,[33] Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff. RTED produces a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the Dispatch Instructions.

---

[33] CAISO verifies that the total incremental amount matches what is needed by the Generation dispatch desk, also verifies that resources that were subject to an outage are not part of the dispatch.

The objective of RTM is system balancing and Load following above and beyond the normal function of the AGC. AGC is mainly a control tool rather than an Energy service. As AGC units respond to frequency and net Interchange deviations, they temporarily supply or consume balancing Energy, thus moving away from their Preferred Operating Point (POP). The CAISO balances the Energy needs of on a 5-minute interval basis using resources that participate in the RTM which allows the CAISO to move AGC units closer to their POPs.

Resource schedule deviations are classified into instructed and uninstructed. Instructed deviations are the result of participating resources responding to Dispatch Instructions. Uninstructed deviations are the result of Load forecast errors (i.e., a Load resource that varies from its schedule), Forced Outages and contingencies, strategic behavior, modeling limitations, failure to follow Dispatch Instructions, etc. Instructed deviations are price setters, whereas Uninstructed Deviations are Price Takers and may be subjected to penalties. Uninstructed deviations prompt the response of AGC to balance the system. The Dispatch Instructions for subsequent Dispatch Intervals then take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement. The Dispatch Instructions for each run of the RTED or RTCD meet the projected Energy requirements over the Time Horizon of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast of CAISO Demand, adjusted as necessary to reflect scheduled changes to Interchange and non-Dispatchable resources in subsequent Dispatch Intervals. In the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drop, the CAISO will dispatch Energy or Operating Reserve in the RTM, to restore Regulation margin.

The Dispatch of the selected resources by RTED should result in a feasible outcome, i.e., no resource, network, or security constraints should be violated. Furthermore, if there are any such violations due to system condition changes, resources should be re-dispatched to remove these violations even if there is no system imbalance.

Exhibit 7-5 shows the timeline for RTED, the linkage to ADS, and the corresponding MW versus time graph. The purpose of this timeline is to define the various elements in the Dispatch process – from telemetry input to Dispatch Instruction output.

Exhibit 7-5: RTED Timeline
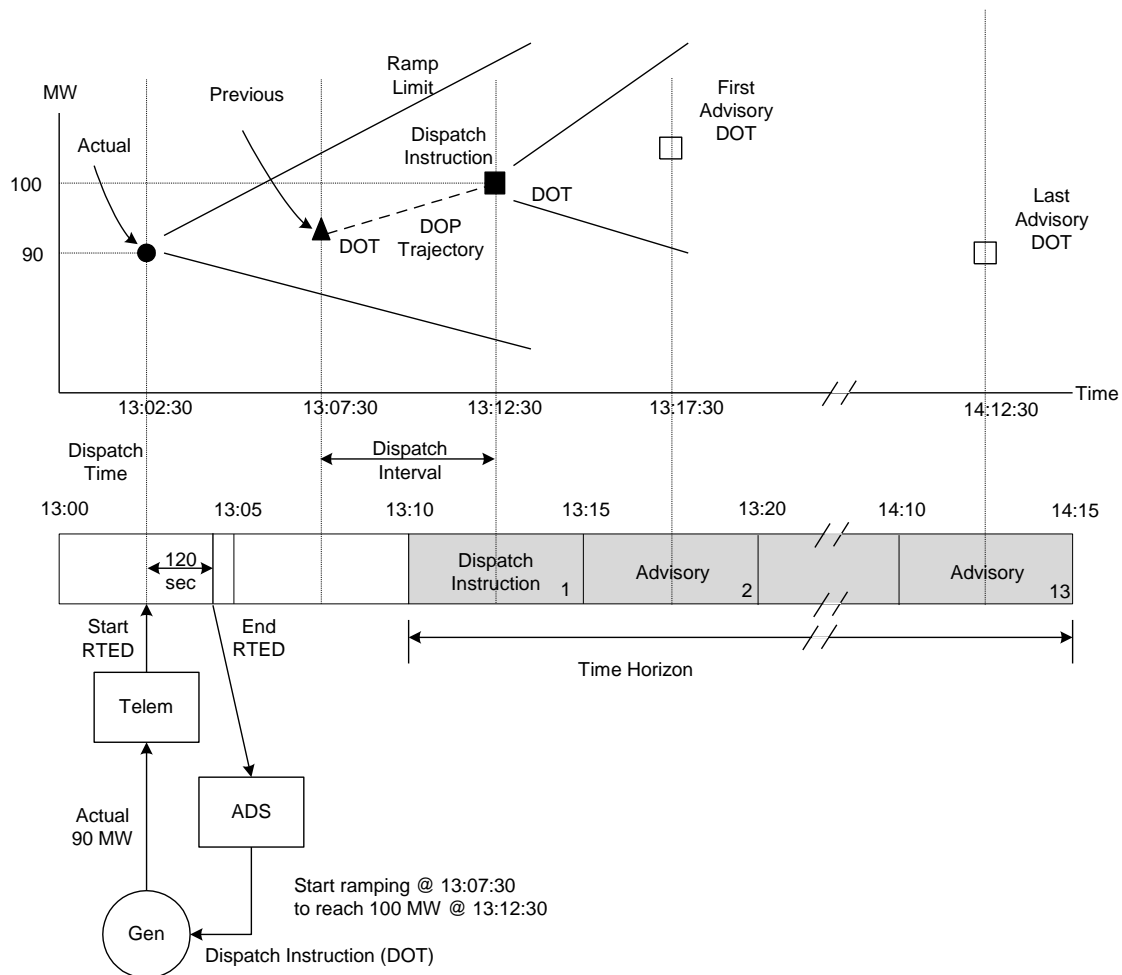
7.8.1   Real-Time Economic Dispatch Inputs

This section identifies those inputs that are particularly specific to RTED. Inputs that are common to all DAM functions are identified in earlier sections of this BPM:

➢ Real-Time information from the EMS

7.8.1.1   Real-Time Economic Dispatch Initialization

The RTM applications employ a FNM and enforce all network constraints calculating an LMP at each PNode. In this model, the optimal Dispatch must be accurate and realistic at the resource level. The Dispatch approach is to initialize the optimal Dispatch of each participating resource at a calculated operating point obtained from the current SE solution, or optionally the telemetry (when available and reliable), considering the applicable Ramp Rate and capacity limits. This

calculated operating point is derived as a 5-minute extrapolation of the SE solution (or telemetry) towards the last issued DOT. When the SE solution or the telemetry is bad or unavailable, the last DOT can be used for initialization.

The advantage of this dispatch approach is that Uninstructed Deviations are taken into account in the calculation of the optimal Dispatch so that Dispatch Instructions are always feasible at the resource level.

RTED does not run a power flow in itself. The Full Network Model attributes i.e shift factors and loss factors to be used in RTED are based on the last network model information update from FMM. RTED runs a power flow in itself and uses updated FNM information if triggered event i.e. topology change information is provided by the SE solution.

7.8.1.2 Dispatch of Resources that have not submitted RTM bid but have telemetry value

If there is no Energy Bid or a Self-Schedule for a dispatchable Generating Unit or Dynamic System Resource, but the resource is on-line and there is a positive telemetry for that resource, RTED will treat this resource internally as fixed at its telemetry value and will send a zero DOT for that resource through ADS. RTED will continue dispatching the resource in this manner until the resource shuts down, or a scheduled start-up is reached, after which an Energy Bid or a Self-Schedule is available for that resource so that RTED can dispatch it optimally. This does not apply to PDR resources. If a PDR resource does not have a bid, it will be considered as offline.

7.8.1.3 Automated Load Forecasting System (ALFS)

The automated load forecasting System (ALFS) is an application based on advanced neural network and regression models that is designed to capture linear and non-linear interactions between load, weather and calendar information. It uses five-minute averages of actual Load from the Energy Management System for the last 3 years as input for training the neural network. ALFS can generate a forecast for different time intervals and time horizon. CAISO currently uses ALFS to generate a load forecast for the Real-Time market horizon.

The load forecast for any particular day is generated at both system and regional level. In addition to the five main IOU sub-regions (SCE Inland, SCE Coastal, PGE Bay Area, PG&E Non-bay Area, and SDG&E), forecasts at the MSS levels (NCPA, SVP, Anaheim, Riverside and Vernon) and for sub-regions within the IOU such as Humboldt are also generated. The CAISO operator has the option to make manual adjustments to the forecast generated by ALFS for use in the Real-Time Market.

ALFS produces a load forecast for each five-minute Dispatch Interval in the Real-Time Market time horizon. The forecast models use the latest weather forecast available from weather providers in addition to other inputs such as actual load for the real-time forecasts. The load forecast for 15-minute intervals is derived as the average of three relevant five-minute Dispatch Intervals. The CAISO has developed multiple models for Real-Time that generate a forecast every 5 minutes. The CAISO operator has the ability to view and use the assortment of forecasts or the load curve from a similar day or a blend of both in the Real-Time Market.

In addition to weather forecasting, ALFS produces a generation forecast for VER resources based on weather and atmospheric conditions as well as plant information. The forecast is produced for a five-minute Dispatch Interval granularity and is updated every five minutes.

7.8.2   Real-Time Economic Dispatch Constraints & Objectives

The RTD application uses the SCED engine described in Attachment A.2, Security Constrained Economic Dispatch.

RTD will apply the following bid processing for VERs. If the VER has submitted economic Bids, then for each 5-minute interval an upper dispatch limit will be set to the VER's 5-minute persistent forecast as calculated by the SCED for CAISO VER resources. Effectively this means that a VER's bids will be limited or extended to a dynamic upper dispatch limit for each 5-minute interval in the time horizon. For self-scheduled VERs, FMM calculates a self-schedule for each 5-minute interval in the time horizon based on the 5-minute forecast. The resulting set of self-schedules is treated like any other self-scheduled resource.

RTED provides the functionality to classify and prioritize constraints among themselves and the control Dispatch priorities. A common system of priority levels is supported for both resource and Constraint priorities. The priority level for any control or Constraint class is configurable. Control and Constraint classes may share the same priority level.

Initially, all constraints have higher penalty than all resource priorities. The priorities are listed in Section 7.5.1, Hourly Schedule Changes & Dispatch Priorities.

7.8.2.1   Cross-Interval Ramping

The RTM applications calculate the optimal Dispatch to meet the average Demand Forecast in each Dispatch Interval, effectively placing the DOT at the center of the Dispatch Interval. With this calculation, dispatched resources are expected to follow Dispatch Instructions Ramping symmetrically across each Dispatch Interval boundary. A ramp between the centers of consecutive Dispatch Intervals provides the best possible Load following and simplicity since it applies uniformly to all dispatched resources.

This approach was adopted because of its simplicity, transparency, and uniformity, the lower reliance on Regulation, and the beneficial impact in meeting Control Performance Standards (CPS).

7.8.2.2   Imbalance Energy Requirement & Bias

The Imbalance Energy requirement corresponds to the Power balance Constraint in the optimal dispatch formulation. The Imbalance Energy requirement for each time interval in the RTM is calculated as the Load prediction obtained from the VSTLP for that interval, reduced by fixed Supply and the Marginal Losses contribution of participating resources at the base operating point using loss sensitivity factors.

The Marginal Losses contribution of participating (dispatchable) resources must be subtracted because the Load projection includes the system Transmission Losses at the base operating point. The base operating point is a power flow solution obtained at 15-minute intervals from the SCUC solution using a distributed Load slack and is used to linearize the non-linear power flow equations.

The loss sensitivity factors are calculated from sensitivity analysis at that power flow solution, and thus represent a linear Transmission Loss approximation due to both participating resource and non-Participating Load deviations.

In general, there is no need to reflect Uninstructed Deviations in the Imbalance Energy requirement because the Dispatch is initialized at the previous DOT, which is extrapolated from the State Estimator solution, and thus any Uninstructed Deviations are already accounted for.

However, to account for resources that produce Energy during their startup process, the start-up ramp time parameter will be used to predict the resource's output. This parameter, stored in the Master File, applies to Generating Units generally and MSG Configurations. The start-up ramp time is used by the Day-Ahead Market or Real-Time Market to calculate the linear start-up profile for internal imbalance consideration. In cases where the start-up time is zero minutes, the start-up ramp will be considered to be instantaneous at the time of the startup.

In addition, there may be a need to account for resources that are persistently non-responsive to Dispatch Instructions because such non-responsive resources impact the ability of CAISO to satisfy its Imbalance Energy requirements. These resources are flagged as non-compliant and they are treated as fixed at their SE solution for all intervals of the Time Horizon.

The RTM applications provide an interface to the CAISO Operator to adjust/bias the Imbalance Energy requirements within the relevant Time Horizon to reflect information that is known to the CAISO Operator, but not to the RTM. For example, a pending Outage that is not yet reflected in outage management system, a pending curtailment of a large Load, or an expected large

Uninstructed Deviation. The Imbalance Energy bias is used by all RTM applications while in effect.

7.8.2.3   Available Operating Reserve Calculation

SCED calculates the available Operating Reserve for relevant resources in each Dispatch Interval using the applicable Ramp Rate function, the binding DOT, and the Start-Up Time, if applicable. This 10-minute capability, in association with Operating Reserve Dispatch Instructions, is used in the No Pay mechanism to rescind capacity payments for unavailable Operating Reserve.

For example, a resource that at a given DOT has a lower Ramp Rate than was used by Ancillary Service management to procure Operating Reserve; it may be incapable of providing the awarded Operating Reserve in full within the time frame awarded. Another example is a resource that has suffered a partial or full Outage that has reduced its Maximum Operating Limit or its Ramp Rate.

The available Operating Reserve calculation is to be used by the No Pay mechanism (described in more detail in the BPM for Compliance Monitoring) and other CAISO processes.

The available Operating Reserve calculation is performed on all resources that have capacity covered by Bids (whether submitted or inserted) regardless of whether Ancillary Services have been awarded and regardless of the resource's on-line status. This is based on Section 8.10.8 of the CAISO Tariff. Only interties (Non-Dynamic System Resources) are exempted from this requirement.

The available Operating Reserve is calculated for every Generating Resource and Dynamic System Resource with Energy Bids and/or Ancillary Service Awards for a 10 minute period starting at the binding DOT.

The available Operating Reserve for online Generating Resources is calculated using the applicable Operational Ramp Rate function ORR(P), which could be static or dynamic and may reflect applicable ramp rate derates, and it is limited from above by the lower of the applicable

Upper Economic Limit (UEL) or Upper Operating Limit (UOL). The UEL is the top of the Energy Bid, whereas the UOL is the registered Generating Resource Maximum Capacity, reduced by any applicable derates. Note that the Upper Regulating Limit (URL) is ignored in this calculation even if the Generating Resource is on Regulation because it is assumed that the resource can be taken off Regulation if that is necessary to dispatch Operating Reserve.

Let $RRU_\tau(P)$ be the function that returns the maximum incremental dispatch from P within time τ using ORR(P). Then, the available Operating Reserve (AOR) for online resources is calculated as follows:

$$AOR = \max\left(0,\ \min\left(RRU_{10'}(DOT),\ UEL - DOT,\ UOL - DOT\right)\right)$$

Example:

Pmin = LOL = 50 MW; Pmax = UOL = 200 MW; UEL = 150 MW; DOT = 80 MW.

$$ORR(P) = \begin{cases} 4\,\text{MW/min} & \because\ 50\,\text{MW} < P < 100\,\text{MW} \\ 5\,\text{MW/min} & \because\ 100\,\text{MW} < P < 150\,\text{MW} \\ 2\,\text{MW/min} & \because\ 150\,\text{MW} < P < 200\,\text{MW} \end{cases} \implies RRU_{10'}(DOT) = 45\,\text{MW}$$

Then:

$$AOR = 45\,\text{MW}$$

The available Operating Reserve for offline Generating Resources with Non-Spinning Reserve Awards is calculated using the applicable Lower Operating Limit (LOL), Start-Up Time SUT(OFF(t)), Off Time OFF(t), and Operational Ramp Rate function ORR(P), which could be

static or dynamic and may reflect applicable ramp rate derates, and it is limited from above by the lower of the applicable Upper Economic Limit (UEL) or Upper Operating Limit (UOL). The LOL is the registered Generating Resource Minimum Load, increased by any applicable overrates. The Off Time and SUT are evaluated at the start of the Time Horizon T_r. Then, the AOR is calculated as follows:

$$
AOR = \begin{cases} \min\left(LOL + RRU_{10'-SUT(OFF(T_r))}(LOL), UEL, UOL\right) & \because \quad SUT\left(OFF(T_r)\right) \leq 10' \\ 0 & \because \quad SUT\left(OFF(T_r)\right) > 10' \end{cases}
$$

Example:

Same example as before, but the unit is now offline at T_r and the DOT is zero with:

$$
OFF(T_r) = 50\,\text{min}
$$

And:

$$
SUT(OFF) = \begin{cases} 7\,\text{min} & \because \quad OFF < 60\,\text{min} \\ 20\,\text{min} & \because \quad 60\,\text{min} \leq OFF < 240\,\text{min} \quad \Rightarrow \quad SUT(T_r) = 7\,\text{min} \\ 60\,\text{min} & \because \quad 240\,\text{min} \leq OFF \end{cases}
$$

Then:

$$
RRU_{3'}(LOL) = 12\,\text{MW}
$$

Thus:

$AOR = 50 + 12 = 62\,\text{MW}$

Note that if there is no Energy Bid, the UEL is equal to the Total Self-Schedule, and if there is no Self-Schedule it defaults to the LOL.

If RTM fails, or it is skipped either because of manual intervention or because of switching to RTCD that has a 10-min time horizon, there may be a Dispatch Interval without available Operating Reserve. For RTM failures or a Dispatch Interval without available Operating Reserve, the No Pay mechanism will set the available Operating Reserve to an extremely high value, 999 MW, such that all Operating Reserve is available in that Dispatch Interval.

7.8.2.4   Forbidden Operating Regions

Forbidden Operating Regions (FORs) are distinct non-overlapping operating regions within which Generating Units cannot operate stably. A Generating Unit may be scheduled or Dispatched within an FOR in an interval only if it takes longer than the duration of the interval to cross that region. In such case, the Generating Unit must be scheduled or Dispatched in subsequent intervals in the same direction (up or down) so that it clears the FOR in the least number of intervals possible. Depending on its Crossing Time, a resource may be dispatched to the boundary of its FOR before proceeding to cross the FOR in subsequent interval(s).

FORs are static and defined in the Master File along with all other resource characteristics. There is support for up to four FORs for a given Generating Unit, however, not all resources have FORs. The market applications obtain the static FOR definition directly from the Master File along with all other resource characteristics. The Operational Ramp Rate Bid is currently limited by SIBR validation to four segments without regard to FORs.

The Forbidden Operating Region Ramp Rates, are static and are included in the FOR definition in the Master File, albeit not as Ramp Rates, but as Crossing Times; an average Ramp Rate can be derived by dividing the range of the FOR with its Crossing Time.

If there are registered FORs for the Generating Unit and the Bid period specified in the Bid, the Operational Ramp Rate curve specified in the Generating Unit Operational Ramp Rate Bid component is modified so that the operating range covering each FOR has an operational ramp

rate equal to the ratio of the FOR range over the corresponding registered Crossing Time, subject to the 10:1 rule specified in section 6.6.2 of this BPM.

In the Real-Time Market, the above Forbidden Operating Region rules apply in conjunction with the rules for application of Self-Schedules and Economic Bids submitted by the Scheduling Coordinator, as further described below.

> ➢ In the event that a Scheduling Coordinator submits a Self-Schedule within a Forbidden Operating Region, the CAISO will honor the Self-Schedule and the Forbidden Operating Region will not be observed. In this instance the unit's dispatch is driven by Self-Schedule and the CAISO Market solution will drive the unit as instructed by the Self-Schedule to the Self-Scheduled MW value.

> ➢ The Dispatch for the Generating Unit is fixed at its telemetry MW value if Generating Unit's effective Energy economic range [Pmin, Pmax] lies completely within the Forbidden Operating Region because of either: 1) the Bids submitted by the Scheduling Coordinator; or 2) conditions such as MSS load following up, MSS load following down, Ancillary Services, de-rate or rerate conditions, etc. ,, .

> ➢ In the Real-Time Dispatch only, if the resource only has Self-Schedules (without Economic Bids) for sequential hours and is crossing the Forbidden Operating Region between the Self-Schedules, then the Forbidden Operating Region implicit ramp rate is ignored and the 20 minute Self-Schedule ramping rule will be used as described in section 7.6.3.1 of this BPM.

It should be noted that the Forbidden Operating Region rules will prevail in other cases, including where the resource has Self-Schedules with Economic Bids and is crossing the Forbidden Operating Region between the Self-Schedules. There will be times when the next hours Self-Schedule appears in the time horizon and the Generating Unit is already crossing the Forbidden Operation Region in a direction away from that Self-Schedule. In these cases the Dispatch will continue to honor the Forbidden Operation Region rules, crossing through the Forbidden Operating Region until the boundary is reached, and as required crosses back towards the next hour's Self-Schedule. Depending on the crossing time, the Generating Unit may not reach its Self-Schedule value until well after the beginning of the hour.

7.8.2.5   Stored Energy Management for Non Generator Resources in Real-Time

For Non-Generator Resources (NGRs), state of charge (SOC) constraints shall be applied to both the binding and non-binding intervals in RTED.   To properly manage the SOC, RTED receives the latest SOC for each NGR via telemetry, and uses this information to calculate an

initial condition SOC for each NGR, similar to the way generator initial operating levels are calculated, by projecting the actual status toward the last dispatch.

For NGRs using Regulation Energy Management functionality the optimization shall minimize the total weighted violations of each interval in the optimization horizon. For purposes of this section, a violation is defined to mean that the resource's SOC cannot fully support regulation awards.   The goal in RTED is to protect the resource's available regulation capacity as much as possible for the binding interval based on SOC.

In addition for NGR using Regulation Energy Management functionality, automatic generation control (AGC) shall apply a 50% rule that:

- Maintains the SOC at 50% if system conditions are normal and it is not impacting the grid reliability by doing so.
- If SOC is below 50% and the system needs Regulation Down energy, AGC will calculate the MW charge level, and send a set point to NGRs for charging.
- If SOC is above 50% and system needs Regulation Up energy, AGC will calculate the MW charge level, and send a set point to the NGR for discharging.

7.8.3   Real-Time Economic Dispatch Outputs

RTED outputs the following. Both the binding awards and information from the first interval and the advisory results from the remaining intervals in the RTD time horizon are available to SCs.

➢ **Dispatch Instruction** –DOT (the binding one) as modified by the CAISO Operator is required and is sent to ADS. This instruction includes a breakdown of the DOT into its service components. Note also that no Energy calculation is needed at this step since the breakdown is a MW breakdown of the MW instruction. In any given interval where the software solution does not converge, the CAISO will send binding Dispatch Instructions and advisory results based on advisory results applicable to this interval obtained from the previous successful RTED run. In such cases, all 5-minute data including DOP, DOT, LMP prices and other supporting data is copied from the advisory results of the previous run.

➢ **Exceptional Dispatches** – Exceptional Dispatches are manually determined but enforced in RTM and sent to ADS when they are issued. Several non-conflicting Exceptional Dispatches may be present for each dispatchable resource in the current and next hour.

➢ **VER forecast** – The 5-minute resource specific forecast used in RTD will be reported to SCs.

7.8.3.1   Dispatch Operating Target Breakdown

The Dispatch Operating Target or DOT is broken down into various MW service components in ADS.

The DOT breakdown that CAISO provides to market participants through ADS is to illustrate the Energy component of the Dispatch Instructions in terms of MW capacity constituting the total DOT MW. This breakdown is used by the CAISO for operational purposes including but not limited to, compliance checking and available operating reserve calculation. It is also used by market participants for shadow settlement purposes.

Although the DOT breakdown is used to represent Energy components of the Dispatch Instructions, they are calculated and represented in terms of MW capacity and hence they do not represent the energy difference due to ramping between intervals.

There are two types of real-time Dispatch Instructions that CAISO sends out through ADS, i.e., hourly pre-dispatch instruction and real-time dispatch instruction. There are differences in how to interpret and use the DOT breakdown MWs between the two types of instructions.

7.8.3.1.1   DOT Breakdown in Non-Dynamic System Resource Instruction

These instructions apply to Non-Dynamic System Resources dispatched in FMM, including HASP. There are two critical components:

- SCHED: The SCHED MW reflects the final day-ahead energy schedule.

- SUPP: The SUPP MW is the difference between DOT and SCHED. It is effectively the incremental (positive) or decremental (negative) value from the Self-Schedule MW.

Although the standard ramp RMPS is also calculated for the intertie System Resources in the DOT breakdown, the standard ramp has little relevance to the ultimate energy settlement of hourly pre-dispatched system resources since such energy is accounted for on a block basis. There will not be any Spin or Non-spin MWs for hourly pre-dispatched resources since we do not model AS import on the hourly pre-dispatched resources. Note also that there are two scenarios under which the SCHED will be equal to the final Day-Ahead Schedule for Energy,

Scenario 1: Market participants who elects to submit a real-time self schedule and/or real-time energy bid curve on top of the real-time self schedule. Under this Scenario, the SCHED value

stays as the day-ahead energy schedule MW regardless of the real-time self-schedule MW value. The Supply value is then representing effectively the incremental or decremental offer in real-time.

Scenario 2: No explicit real-time energy bid curve or self schedule is submitted. SIBR will convert the final DA energy schedule into a real-time self schedule

Following examples assume a final day-ahead energy schedule MW as 80MW.

Example 2.1 (incremental),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

Example 2.2 (decremental),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

7.8.3.1.2   ADS Decline Functionality for Non-Dynamic System Resource Instruction

In ADS, the ISO allows the market participants to decline or partially accept an hourly dispatch schedule or FMM advisory Intertie Schedule for Non-Dynamic System Resources other than VERs using the self-scheduled option.[34] It is CAISO's policy that the entire MW threshold value can be rejected or partially accepted. A final accepted DOT is recorded in ADS and available to market participant as "Accept DOT".

---

[34] Excessive declines of instructions for Non-Dynamic System Resources can be subject to penalties.

The MW threshold value is calculated as follows:

> ➢ For resources that have selected the bid options of Self-scheduled hourly block, Economic bid hourly block, or Economic bid hourly block with single intra-hour economic schedule change, the accept/decline MW threshold is max of the RUC schedule or the hourly schedule of the HASP.

> ➢ For resources that have selected the bid options of Economic bid with participation in 15-minute market, the accept/decline MW threshold is the max of RUC schedule or the largest of the four 15-minute interval advisory schedules of HASP.

The SC has five minutes to respond to the instructions in ADS following the publication of the HASP results. If the SC does not respond, the instruction will default to accept the schedule generated by the HASP market run. In the event that the SC is unable to respond to instructions, the CAISO Operator has the ability to manually change (decline or partially accept) the ADS accepted instruction on the Scheduling Coordinators behalf until T-40

Decline/Partial Accept for example 2.1,

Market participants can decline the entire amount or partially accept any portion of the 20MW. Therefore the Accept DOT will be any number between 0MW to 100MW.

Decline of 100 MW: Accept DOT will become 0MW;

Partially acceptance of 10MW out of 20MW: Accept DOT will become 90MW;

Full acceptance of 20MW: Accept DOT will stay as 100MW.

Decline/Partial Accept for example 2.2,

Market participants can decline the entire amount, accept the -20 MW or partially accept any portion of the -20MW. Therefore the Accept DOT will be any number between 0MW to 80MW.

Decline of 80MW: Accept DOT will become 0MW;

Partially acceptance of -10MW out of -20: Accept DOT will become 70MW;

Full acceptance of -20MW: Accept DOT will stay as 60MW.

7.8.3.1.3   DOT Breakdown in Real-time Dispatch Instruction

The real-time Dispatch Instructions apply to non-hourly pre-dispatch resources, i.e., the Generating Units, tie generators (including Dynamic System Resources and the resources used to model AS import on the ties) and Participating Loads (using the pump-storage model). There are five critical components:

SCHED: The SCHED MW reflects the real-time Energy Self-Schedule for that resource in the SIBR clean bid.

SUPP: The SUPP MW is the difference between DOT and SCHED ~~calculated by (DOT – SCHED).~~ It reflects the incremental (positive) or decremental (negative) value from the Self-Schedule MW. SUPP is inclusive of the SPIN and NSPN MWs and MSSLF whichever applicable.

SPIN: If the resource gets dispatched out of Spinning Operating Reserve capacity (either in contingency or non-contingency mode[35]), this value will reflect dispatched SPIN capacity amount. Otherwise, this amount is zero. SPIN MW can be used for available reserve calculation.

NSPN: If the resource gets dispatched out of Non-Spinning Operating Reserve capacity (either in contingency or non-contingency mode[36]), this value will reflect dispatched Non-Spin capacity amount. Otherwise, this amount is zero. Non-SPIN MW can be used for available reserve calculation.

MSSLF: This only applies to MSS load following resources. If market participants submit MSS load following instructions for the resource, the validated load following instructions will be sent back through this component. For all non-load following resources, this amount will be zero.

---

[35] A contingency AS can only be dispatched in a contingency dispatch run or if the resource is flagged as contingency individually. A non-contingent AS can be dispatched in a normal real-time interval dispatch.

[36] See Note 1.

Although the standard ramp RMPS is also provided for the real-time Dispatch Instructions in the DOT breakdown, it is recommended the value of RMPS be determined outside of the Dispatch Instruction based on the WECC standard ramp - 20 minute cross-hour ramp between Day-Ahead Schedules over the top of the hour. It is also worth mentioning that, there are two scenarios under which the SCHED will be equal to the final Day-Ahead Schedule for Energy

- **Scenario 1**, for the Market Participants that elects to protect their Day-Ahead Schedule for Energy from changing through the RTM, by itself submitting a Self-Schedule for that same capacity in the Real-Time Market.

- **Scenario 2**: The Market Participant does not submit an explicit Real-Time Energy Bid Curve or Self-Schedule for the MW Energy capacity identified in the Day-Ahead Schedule. SIBR will convert the final Day-Ahead Schedule for Energy into a real-time self-schedule.

Following examples assume a real-time self schedule MW as 80MW,

Example 3.1 (incremental without dispatch out of Spin or Non-Spin),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

Example 3.2 (incremental with dispatch out of Spin and Non-Spin),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

SPIN: +5MW

NSPN: +5MW

In example 3.2, the 5 MWs dispatched out of Spin and Non-spin are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin and Non-spin, it implies the 20 − 5 -5 = 10MW as the market energy dispatch component.

Example 3.3 (decremental),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

Example 3.4 (incremental with dispatch out of Spin, Non-Spin and Load following),

DOT: 100MW

DOT breakdown is,

SCHED: +80MW

SUPP: +20MW

SPIN: +5MW

NSPN: +5MW

MSSLF: +5MW

In example 3.4, the 5 MWs dispatched out of Spin, Non-spin and MSS load following are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin, Non-spin and MSSLF, it implies the 20 − 5 -5 − 5 = 5MW as the market energy dispatch component not associated with any other capacity.

Example 3.5 (decremental with MSS load following),

DOT: 60MW

DOT breakdown is,

SCHED: +80MW

SUPP: -20MW

MSSLF: -5MW

In example 3.5, the -5 MWs for MSS load following are part of the SUPP as the decremental amount. Besides the -5 MWs from MSSLF, it implies the -20 – (-5) = -15MW as the market energy dispatch component.

7.9   Real-Time Contingency Dispatch

This section is based on CAISO Tariff Section 34.3.2, Real-Time Contingency Dispatch.

The Real-Time Contingency Dispatch (RTCD) mode of operation is run in response to a significant Contingency event, such that waiting until the next normal RTED run is not adequate and/or Operating Reserves identified as Contingency Only need to be activated in response to the event. The CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource-specific basis or for all such resources.

When activating Contingency Only reserves in RTCD, the original Energy Bids associated with the resources providing Operating Reserve are used for the RTCD (CAISO Tariff Section 34.3.2.1). In this case, Dispatch and pricing will be based on original submitted Energy Bids as mitigated by MPM. If no Contingency event has occurred but the CAISO has run out of Economic Bids, the CAISO may dispatch Contingency Only resources in RTED. The RTED will dispatch such resources using Energy Bid cap as provided in Section 39.6.1.1 and will set prices accordingly.

RTCD uses SCED to produce an optimized set of Dispatch Instructions for a single 10-minute Dispatch Interval instead of a normal five-minute Dispatch Interval. It is possible that Dispatch Instructions are issued more than once in the same 5-minute Interval, once from RTED and then later from RTCD. Resources must respond to RTCD Dispatch Instructions as soon as possible. The Dispatch Instructions from RTCD override any previously issued Dispatch Instructions from RTED.

After review by the CAISO Operator, Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff. When activating an RTCD run and returning to a normal RTED run after an RTCD run, five-minute Dispatch Interval LMPs are produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

The RTCD application can be activated at any time to address contingencies by dispatching contingent Operating Reserve. Ideally, RTCD should be activated when a State Estimator

solution is available after the occurrence of a Contingency that qualifies as a significant event. The SE solution is available normally at the middle of five-minute clock intervals to provide a base operating point for RTED. Nevertheless, SE may also execute and produce a solution immediately after a significant event without waiting for the next regular execution time.

The RTCD is different from the RTED in the following aspects:

➤ The Dispatch time can be any time.

➤ When the RTCD is activated, the RTED or RTMD, whichever mode is active, is immediately suspended and may not resume until after the next five-minute Dispatch time.

➤ Any pending Dispatch Instructions before the RTCD is activated are discarded and not sent to ADS.

➤ The RTCD has a single 10-minute Dispatch Interval. A 10-minute Dispatch Interval is used so that Non-Spinning Reserve from resources with zero Minimum Load and no inter-temporal constraints can be optimally Dispatched.

➤ The time delay between the time the dispatch is initiated and the start of the ramp for the DOT is configurable and initially set to two to three minutes, depending on the complexity of the options chosen by the operator. If the operator chooses a more complex operating mode that typically requires a longer solution time, the three minute value is used, otherwise the two minute value is used. Taking into account the optimization run time and communication delays in ADS, the start of the ramp for the DOT will occur about 90 seconds after receipt of the ADS dispatch instruction. However, because the RTCD is activated in response to a Contingency event, it is expected that resources respond to RTCD instructions as soon as possible.

➤ Contingent Operating Reserve Bids are automatically released for optimal Dispatch.

➤ Configurable parameters in RTCD allow the CAISO operator to exclude certain resources from consideration for dispatch:

   ➤ Exclude Northern Ties: When the Operator selects this option, the RTCD shall not increment any intertie resources north of Path 26.

   ➤ Exclude Southern Ties: When the Operator selects this option, the RTCD shall not increment any intertie resources south of Path 26.

➢ The Dispatch must be sent to ADS manually by the CAISO Operator; no automatic transfer takes place.

The RTCD calculates a contingent Dispatch for the 10-minute Dispatch Interval, presents the Dispatch to the CAISO Operator, and awaits approval. The CAISO Operator may block or edit individual Dispatches as usual, and then manually sends the Dispatch to ADS, or blocks and discards the entire Dispatch. The RTCD stays idle afterwards awaiting CAISO Operator action, however, the RTUC continues running every 15 minutes.

The CAISO Operator may manually initiate another RTCD run, or switch to RTED or RTMD, which resumes at the next applicable dispatch time (the midpoint of a five-minute clock interval). The RTED or RTMD inherits the global Contingency status from the RTCD and does not automatically unload contingent Operating Reserve. That action is performed by the CAISO Operator manually resetting the resource-specific Contingency Flags gradually during the remainder of the hour (in reverse merit order of their Energy Bid). This gradual reserve pickup is necessary to avoid large Generation swings immediately after surviving a Contingency.

A special mode of RTCD, called Real-Time Disturbance Dispatch or RTDD (CAISO Tariff Section 34.3.2.2), can be invoked by the CAISO Operator when 300 MW or more of capacity is needed to respond to a significant Contingency event. RTDD will not use SCED. RTDD is a merit order dispatch without a network model.

➢ Under RTDD, priority will be given to resources with available Operating Reserve capacity, then to resources with ramping capability as follows. Tier 1 resources will be selected before Tier 2.

➢ Tier 1: Resources with Spinning Reserves and Non-Spinning Reserves will be chosen in merit order of price for Operating Reserves, not Energy Bid price. For example, if the CAISO needs 100 MW and there are two units (A and B) providing Operating Reserves, with unit A being awarded 10 MW at $10/MW, unit B being awarded 100 MW at $15/MW, the order will be 10 MW from unit A and 90 MW from unit B.

➢ Tier 2: Resources with Energy-only bids or resources with remaining available ramping capability will be chosen in descending order of effective available MW within the 10-minute ramping capability of the unit (i.e., the remaining amount after considering the available Operating Reserves from Tier 1 above). For example, If after exhausting all the available capacity in Tier 1, the CAISO needs 50 more MW and there are two units (A and B) with Energy-only bids and available ramping capability, unit A with 10 MW of ramping capability at $10/MW and unit B with 100

MW of ramping capability at $15/MW, the system will use 50 MW from unit B even though it is more expensive.

➤ At the CAISO Operator's discretion, priority may be given to resources located in a particular dispatch region within the CAISO balancing authority. For example, if a major resource trips in the San Diego area, the CAISO Operator may want to give dispatch priority to the remaining resources in the San Diego area to ensure recovery from the disturbance. A parameter in RTDD will allow the operator to determine whether to give priority to dispatch regions and, if so, which dispatch region to give priority to.

➤ Resources must respond to RTDD Dispatch Instructions as soon as possible.

➤ RTDD will not enforce transmission constraints. In addition the dispatch will be a uni-directional dispatch, since the expectation is that resources would be dispatched upward to make up for the lost energy due to the contingency.

7.9.1   Real-Time Contingency Dispatch Inputs

This section lists the inputs that are particularly specific to RTCD. Inputs that are common to all the DAM functions are identified in earlier sections of this BPM:

➤ The Load prediction for the RTCD Dispatch Interval is the projected average of the system Load over the 10-minute RTCD Dispatch Interval. It is derived as a time-weighted average of the Load prediction for the overlapping five-minute clock Dispatch Intervals.

➤ The Load prediction may be adjusted by CAISO Operator to reflect actual conditions that could not be incorporated into the prediction.

7.9.2   Real-Time Contingency Dispatch Constraints & Objectives

RTCD uses SCED to produce an optimized set of Dispatch Instructions for a single 10-minute Dispatch Interval instead of a normal five-minute Dispatch Interval. After being reviewed by the CAISO Operator, Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3 of the CAISO Tariff.

7.9.3   Real-Time Contingency Dispatch Locational Marginal Prices and Load Forecast

Metering and Settlement are aligned with five-minute clock Dispatch Interval, hence LMPs must be determined for the same intervals. This is not a problem for the RTED or RTMD since they both align with five-minute clock Dispatch Intervals, and if a RTMD run is skipped, the MCP

remains the same as that of the previous Dispatch Interval. However, the RTCD Dispatch Intervals, and thus the RTCD LMPs, do not align with five-minute clock Dispatch Intervals. In this case, the rules for determining the five-minute clock Dispatch Interval LMPs are as follows:

➢ The RTCD LMPs determine the five-minute clock Dispatch Interval LMPs for all five-minute clock Dispatch Intervals that overlap with the RTCD Dispatch Interval.

➢ The final five-minute clock Dispatch Interval LMP, which is used for Settlement, is the last determined LMP for that Dispatch Interval, if there are multiple instances due to Dispatch overlap or multiple Dispatch runs.

➢ If LMPs for a five-minute clock Dispatch Interval are somehow undetermined, e.g., because a Dispatch was skipped or missed, the LMPs for the previous five-minute clock Dispatch Interval apply.

In general, the RTCD Dispatch Interval overlaps with three five-minute clock Dispatch Intervals. Assuming normal transition from RTED to RTCD and then back to RTED, the LMPs for the three overlapping five-minute clock Dispatch Intervals are determined according to the rules as follows:

➢ The LMPs for the first five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are first calculated by the last RTED run, but then are overwritten with the RTCD LMPs.

➢ The LMPs for the second five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are the RTCD LMPs. No binding LMPs are available from RTED for this interval.

➢ The LMPs for the third five-minute clock Dispatch Interval that overlaps with the RTCD Dispatch Interval are first calculated by RTCD, but then are overwritten by the next RTED LMPs.

LMPs in the RTCD are calculated in the same manner as in the RTED, except that LMPs in the RTDD are determined on a system-wide basis. Under RTDD dispatches, the system marginal Energy component is set to the Energy Bid of the highest-priced resource dispatched, regardless of in which tier or dispatch region the resource was dispatched. The marginal loss and congestion components are zero in the RTDD.

Similar to LMPs, Settlement uses a five-minute clock Dispatch Interval load forecast. The forecast is used to weigh the five-minute clock Dispatch Interval LMP for production of an hourly weighted average price for non-participating load imbalance deviations. In order to provide the

correct weighting, the five minute clock Dispatch Interval load forecast under a RTCD run is determined in the same manner as described for the LMPs above, using the RTCD 10-minute load forecast, including any operator adjustments.

7.9.4   Real-Time Contingency Dispatch Outputs

When activating a RTCD and returning to normal RTED run after a RTCD run, five-minute Dispatch Interval LMPs are produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

7.9.4.1 Real-Time Dispatch Logic for Non-Dynamic System Resources

In general, the Real-Time Dispatch will match energy awards from HASP or FMM, including any adjustments by CAS. However, if the CAISO awards a Non-Dynamic System Resource Ancillary Services in the IFM or HASP and issues a Dispatch Instruction in the middle of the Trading Hour for Energy associated with its Ancillary Services (Operating Reserve) capacity, the CAISO will Dispatch the Non-Dynamic System Resource to operate at a constant level until the end of the Trading Hour. This means that Dispatch outputs from subsequent RTED or RTCD for the rest of the Trading Hour will be set at the constant level unless adjusted by a later CAS confirmed Dispatch. If the CAISO dispatches a Non-Dynamic System Resource such that the Dispatch (DOT) at the end of the 10-min ramp is in the next Trading Hour, the CAISO will dispatch Energy from the Non-Dynamic System Resource at a constant level until the end of the next Trading Hour using the Energy Bid and Operating Reserve award for that hour. The dispatched Energy will not exceed the awarded Operating Reserve capacity in the next Trading Hour. The energy associated with ancillary services from a Non-Dynamic System Resource can only be dispatched once during an hour.

7.10   Real-Time Manual Dispatch

This section is based on CAISO Tariff Section 34.3.3, Real-Time Manual Dispatch.

The Real-Time Manual Dispatch (RTMD) mode of operation is a merit-order run activated upon CAISO Operator action as a backup process in case the normal RTED process fails and expected to continue to fail to converge and solve. This may be due to invalid or unreasonable resource constraints, problems with the AC powerflow solutions, unreasonable transmission constraints, issues with State Estimator solution, or other adverse system conditions. The CAISO Operator may relax certain constraints or choose to solve a Powerflow as part of the

RTED before they revert to a RTMD. The RTMD run provides the CAISO Operator a list of resources and quantity of MW available for Dispatch in merit-order based on Operational Ramp Rate but otherwise ignores Transmission Losses and network constraints.

The CAISO Operator may Dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the system and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by the CAISO Operator, Dispatch Instructions are communicated in accordance with Section 6.3 of the CAISO Tariff.

While the RTMD mode is being used for Dispatch, a uniform five-minute Market Clearing Price (MCP) is produced for all PNodes based on the merit order Dispatch.

Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs are set to the last LMP at each PNode produced by the last RTED run that converged.

The Real-Time Manual Dispatch application is a backup Dispatch process that can be activated at any time when the RTED fails to converge because of bad data, network model issues, or optimization engine failure. When activated, the RTMD executes every five minutes in place of the RTED at the same dispatch times, until the CAISO Operator switches back to the RTED. However, the other applications, namely RTUC, HASP, and STUC, continue to execute normally every 15 minutes and every hour.

The RTMD is different from the RTED in the following aspects:

➢ RTMD has a single five-minute Dispatch Interval.

➢ Resources are Dispatched in merit order based on Energy Bids and Ramp Rate limits, but ignoring Transmission Losses and network constraints. The CAISO Operator is presented a merit order list of feasible Bids (in terms of ramp capability) and a system Imbalance Energy requirement that needs to be met. Bids are selected, and Dispatched in the merit order list to meet the Imbalance Energy requirement.

➢ The Dispatch must be sent to ADS manually by the CAISO Operator; no automatic transfer takes place.

➢ A system-wide Market Clearing Price (as opposed to LMPs) is produced for the Dispatch Interval. Area or zonal restrictions are dealt with on a manual basis by the CAISO Operator.

Aside from these differences, the Dispatch times are still aligned with the DOTs at the middle of five-minute clock intervals and the resource output is still projected from the actual output at that point in time toward the last DOT.

The RTMD, similarly to the RTED, does not dispatch contingent Operating Reserves under normal system conditions. The RTMD may dispatch contingent Operating Reserves, though when the CAISO Operator activates the Contingency status.

7.10.1   Real-Time Manual Dispatch Inputs

Other than CAISO Operator initiation, this section lists the inputs that are particularly specific to RTMD. Inputs that are common to all the RTM functions are identified in earlier sections of this BPM:

➢ By supplying an Imbalance Energy requirement, RTMD generates a merit order list of instructions.

➢ The CAISO Operator has the ability to manually add, remove, or modify instructions from the merit order list. Resources that are "removed" from the merit order list are not dispatched.

➢ The CAISO Operator has the ability to Dispatch contingent Ancillary Services.

7.10.2   Real-Time Manual Dispatch Constraints & Objectives

Since no SCUC optimization takes place in the RTMD, the execution time is very short. Therefore, the CAISO Operator has a time delay window of about five minutes after the merit order list is presented until the start of the ramp at the middle of the next five-minute clock interval, to review, modify, and commit the Dispatch. If the Dispatch is not sent by that time, it is discarded and a new merit order list is presented for the following Dispatch Interval based on the updated data (actual output and Load prediction) that become available at that time. The DOT and MCP for the Dispatch Interval that the Dispatch is discarded remain equal to the DOT and MCP of the previous Dispatch Interval.

7.10.3   Real-Time Manual Dispatch Outputs

The CAISO Operator manually initiates communication of manual Dispatch Instructions through ADS and the merit order list is updated accordingly.

While the RTMD mode is being used for Dispatch, a uniform five-minute MCP is produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based

Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs are set to the last LMP at each PNode produced by the last RTED run that converged.

7.10.4   Procedures in the Event of Failure of the RTUC/RTED Market Processes.

Consistent with Section 7.7.15 of the CAISO Tariff, in the event of a Market Disruption of the RTUC/RTED, the CAISO will follow the procedures described below. Market Disruption in this context refers to events where the market software applications fail to operate and are unable to send instructions to market participants.

7.10.4.1   RTED (Real-Time Economic Dispatch) Failure

In case of a RTED failure, the CAISO may do nothing and may rely on the binding dispatch results of the previous successful RTED run, i.e., resources should stay at the last good DOT. The binding dispatch results will not be sent through ADS for the failed interval. The binding dispatch results of the previous successful RTED run will also be used for expected energy allocation purposes. Flexible ramping awards shall have the value from the last good FMM interval.

To avoid a full market disruption of a five-minute interval, the ISO may turn off the Forbidden Operating Region functionality for a resource(s) on which the application of the functionality previously caused a failure of a RTED run, then the applicable Dispatch will be the 5-minute Dispatch issued without the Forbidden Operating Region functionality for the affected five minute interval(s).

The CAISO may take other actions to address such Market Disruptions, including implementing Exceptional Dispatches. See section 7.11 for more detail.

7.10.4.2   RTUC failure (including HASP)

In case of a RTUC, FMM or HASP Market Disruption, consistent with Section 7.7.15 and 34.4 of the ISO Tariff, the following procedure will apply:

- (1) Internal generators and tie generators (Dynamic System Resources): Consistent with Section 34.4 of the ISO Tariff, if there is a complete disruption of the RTUC, including the FMM and HASP, the ISO will use the last valid RTUC MWs for purposes of settling fifteen minute schedules, and prices as specified in section 8.2. For AS Awards, the CAISO will rely on the day-ahead ancillary service results relevant to the 15-minute interval in the failed RTUC run as the fall back results for dispatch, and prices as specified in section 8.2. Flexible ramping awards will be considered to have a zero MW value.

- (2) For Intertie resources in case of a failed RTUC run (including HASP): For energy MW the CAISO will rely on the HASP results for settlement purposes if available. If not available, the CAISO will use RUC results relevant to the HASP hour in the failed run as the fall back results for settlement. CAISO will use prices as specified in section 8.2.

- (3) For intertie resources in cases of a disruption of the FMM for purposes of clearing the interties only: The CAISO may experience or institute a market disruption of the Fifteen Minute Market for purposes of clearing the interties only and keep the remaining FMM functionality operational. During such times, the CAISO will only suspend bidding into the Real-time Market for the FMM by intertie resources and only after notifying market participants that the FMM has been interrupted for this purpose. During such times, Scheduling Coordinators will only be allowed to submit Self-Scheduled Hourly Blocks or Economic Hourly Block Bids, and will not be allowed to submit Economic bid hourly block with a single intra-hour schedule change or Economic bid with participation in the fifteen-minute market in for intertie resources. Scheduling Coordinators will be permitted to submit bids for the FMM for internal resources and Dynamic System Resources. For settlement purposes HASP Block Intertie Schedules for Non-Dynamic System Resources will be settled based on the individual fifteen-minute interval LMPs as specified in section 8.2. Hourly ancillary service imports will be settled based on the prices specified in section 8.2. Supply from internal resources and Dynamic System Resources will be untouched and continue to settle based on the applicable tariff rules. Demand resources settled based on the Load Aggregation Points will be settled based

on the RTD Default or Custom LAP Price as defined in Section 27.2.2.2 of the CAISO tariff. Upon cessation of the Market Disruptions, the CAISO shall issue a notice to Scheduling Coordinators providing sufficient advance notice of the first RTM interval in which the above-defined actions will not apply.

-   The CAISO may take other actions to address such Market Disruptions, including implementing Exceptional Dispatches. See section 7.11 for more detail.

The binding Ancillary Service results will not be sent through ADS for the failed interval. For the after-the-fact correction and settlement purpose, CAISO will do the following,

1. Expected energy allocation will use the day-ahead Ancillary Service Award for that interval;

2. There will be no real-time Ancillary Service charge or payment for that interval since all Ancillary Service awards fall back to day-ahead awards;

3. For a Trading Hour with only HASP failure:

3.1. For physical Energy schedules, there will not be any settlement for that Trading Hour since all Intertie schedules fall back to Day-Ahead Market. All Real-Time Market Energy beyond the Day-Ahead Market Schedule will be eventually treated as Operational Adjustment for Settlements purposes and settled at RTD prices.

3.2. For Virtual Bids on the Interties, any Virtual Award will be offset by an equal credit or debit for a net zero settlement.

7.10.4.3   Reporting to affected Scheduling Coordinators

In the event that a Bid is removed, the Scheduling Coordinator's Bid will not be cleared through the specific CAISO Market from which it was removed. The CAISO will notify the Scheduling Coordinator as soon as practicable, but no later than three (3) Business Days, after the applicable Bid was removed and will provide information specifying when its Bid was removed and the nature of the disruption.

7.11   Exceptional Dispatch

This section is based on CAISO Tariff Section 34.11, Exceptional Dispatch.

CAISO may perform Exceptional Dispatches for the circumstances described in section 34.11 of the CAISO Tariff, which may require the issuance of forced Shut-Downs or forced Start-Ups, or forced MSG Transitions. CAISO conducts all Exceptional Dispatches consistent with Good Utility Practice.

Dispatch Instructions issued pursuant to Exceptional Dispatches are entered manually by the CAISO Operator into the RTM optimization software so that they are accounted for and included in the communication of Dispatch Instructions to SCs. CAISO Operators may also communicate an Exceptional Dispatch instruction directly to the Scheduling Coordinator. In addition, CAISO Operators may also manually dispatch Non-Dynamic System Resources but only to the extent Bids from those resources are available, in which case instructions are entered in CAS. The goal of CAISO Operators will be to issue Exceptional Dispatches on a least cost basis.

See CAISO Operating Procedure M-402, Exceptional Dispatch for more information.

Exceptional Dispatches are not derived through the use of the RTM optimization software and are not used to establish the LMPs at the applicable PNodes. CAISO records the circumstances that have led to the Exceptional Dispatch. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch are settled according to the provisions in Section 11, subject to Section 39.10 when Bid mitigation may apply, of the CAISO Tariff.

Resources receiving Exceptional Dispatches may be eligible for supplemental revenues pursuant to CAISO Tariff Section 39 or Interim Capacity Payment Mechanism capacity payments pursuant to CAISO Tariff Section 43. Additional details on eligibility are set forth in the Business Practice Manuals for Reliability Requirements.

7.11.1   System Reliability Exceptional Dispatches

This section is based on CAISO Tariff Section 34.11.1, System Reliability Exceptional Dispatches.

CAISO manually dispatches Generating Units (including Multi-Stage Generating Resources), Participating Loads, Dynamic System Resources, RDRR resources, and Condition 2 RMR Units, in addition to or instead of resources dispatched by RTM optimization software during a

System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling.

A System Emergency is defined by the CAISO Tariff as including any "Condition beyond the normal control of the CAISO that affect the ability of the CAISO Balancing Authority Area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment, tripping of system elements which might result in cascading Outages or to restore operation to meet Applicable Reliability Criteria."

CAISO Operators will utilize its System Emergency Exceptional Dispatch authority unless the more specific authorities under Sections 34.11.2 or 34.11.3, discussed below, are clearly applicable. These would include Exceptional Dispatches for any reason CAISO Operators need to address a System Emergency which cannot be addressed by the RTM optimization or system modeling including: Generation and transmission outages; resource specific constraints, such as Forbidden Operating Regions; market software constraints; transmission related modeling limitations, such as South of P26 – Inability to model the loss of the DC, unless Section 34.11.3 applies, as discussed below.

To the extent possible, CAISO utilizes available and effective Bids from resources before dispatching resources without Bids. To deal with any threats to System Reliability, CAISO also dispatches in the Real-Time, Non-Dynamic System Resources that are not selected by the RTM for Dispatch, but for which the relevant SC has submitted a Bid into RTM.

7.11.2   Other Exceptional Dispatch

This section is based on CAISO Tariff Section 34.11.2, Other Exceptional Dispatch.

CAISO may also issue Exceptional Dispatches to resources in addition to or instead of resources dispatched by the RTM optimization software for the following specific reasons:

1)   Perform A/S testing

2)   Perform pre-commercial operations testing

3)   Perform PMax testing

4)   Mitigate for over-generation

5)   Provide for Black Start

6)   Provide for Voltage Support

7)   Accommodate TOR or ETC self-schedule changes after the Market close of the RTM

8)   Reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC,

9)   In the event of a Market Disruption, to prevent a Market Disruption or to minimize the extent of a Market Disruption; or

10)   To reverse the operating mode of a Pumped-Storage Hydro Unit.

7.11.3   Transmission-Related Modeling Limitations

This section is based on CAISO Tariff Section 34.11.3, Transmission-Related Modeling Limitations.

CAISO Operators may also issue Exceptional Dispatches to address transmission-related modeling limitations in the Full Network Model that arise from transmission maintenance, lack of Voltage Support at proper levels as well as incomplete or incorrect information about the transmission network, for which the Participating Transmission Owners have primary responsibility. The cost allocation, as described in Section 11.5.6.2.5 is different from the cost allocation of System Emergency Exceptional issues pursuant to Section 34.9.1 as Excess Cost Payments will be allocated to the responsible Participating Transmission Owner.

CAISO Operators can also issue Exceptional Dispatches under CAISO Tariff Section 34.11.3 in response to system conditions including threatened or imminent reliability conditions for which the timing of the Real-Time Market optimization and system modeling are either too slow or incapable of bringing the CAISO Controlled Grid back to reliable operations in an appropriate time-frame based on the timing and physical characteristics of available resources to the CAISO. The settlement price and cost allocation for these Exceptional Dispatches are the same as for Exceptional Dispatches issues pursuant to Section 34.11.1.

8. Tagging

8.1 What is an E-Tag?

Pursuant to Appendix A to the ISO tariff, an E-Tag is an electronic tag associated with an Interchange Schedule in accordance with the requirements of WECC.[37] WECC, in turn, defines Electronic Tag or E-Tag as a document describing a physical interchange transaction and its associated participants. In plain terms, an E-Tag is the tool used to track energy delivery from one balancing authority to another balancing authority (*i.e.*, imports and exports) or from the source to the sink Balancing Authority Area (BAA).

8.2 Who Is Required to E-Tags?

Scheduling Coordinators and Purchasing Selling Entities (or other entities with similar NERC and North American Energy Standards Board (NAESB) registration) are required to tag interchange schedules between balancing Authority Areas. Interchange Schedules are Energy Schedules where electric power is transferred between Balancing Authority Areas, and they require coordination among multiple entities. The primary method for providing this coordination is the E-Tag. As detailed below, various entities can communicate important information pertaining to the Interchange transaction to each other via the internet using computer applications, which are based on the E-Tag specifications maintained by the NAESB.

A Scheduling Coordinator can communicate interchange transaction information to reliability entities using E-Tags, including Balancing Authorities such as the ISO. Similarly, a reliability entity can communicate reliability limits on interchange transactions to PSEs and other reliability entities using E-Tags. E-Tags should be prepared by PSEs in accordance with NERC, NAESB, WECC, and ISO requirements to facilitate effective operations between Balancing Authority Areas within the Western Interconnection.

8.2.1 Imports/Exports

E-Tags are required for all interchange transaction schedules, that is, all imports or exports on the interties. Transactions that are entirely within the ISO BAA using ISO transmission such as Scheduling Coordinator to Scheduling Coordinator trades are considered network transmission service and are not tagged.

---

[37] The ISO capitalizes the "E" "E-Tag" even though most entities do not (*i.e.*, e-Tag) to make it clear for the reader that it is a defined term under Appendix A to the ISO tariff.

8.2.1.1   Pseudo-Ties

Virtual interconnections aside, pseudo-tie energy inherently crosses BAAs. Accordingly, Pseudo intertie Energy transactions must be e-Tagged. Pseudo Tie E-Tags will follow the same criteria as Dynamic Tag Types 4. Pursuant to Section 1.2.1.2 of the ISO's pseudo-tie protocol (Appendix N to the ISO tariff), a pseudo-tie generating unit must transfer dynamically its entire output at one associated pre-determined ISO Intertie, and the unit "must be permanently associated with a particular pre-determine ISO Intertie." While the same section gives the ISO the discretion to allow for a change in the pre-established Intertie—subject to approval by affected transmission owners—the ISO currently does not have the technical ability to allow the use of two pre-established locations (*e.g.*, one associated pre-determined Intertie and another associated pre-determined Intertie simultaneously). Pseudo-tie generating units may, however, propose changes to their associated Intertie with advance notice and following Operating Procedure 2510 NERC Tagging Requirements.

8.2.1.2   Dynamic Resources

A "dynamic transfer" is the transfer of energy or ancillary services from resources in one BAA into another BAA.[38] The two basic categories of dynamic transfers are Dynamic Schedules and Pseudo-Ties. A dynamic transfer is a "Dynamic Schedule" when the resource supplying the energy or ancillary services remains under the control of the BAA where the resource is interconnected. The ISO tariff defines Dynamic Schedule as "A telemetered reading or value which is updated in Real-Time and which is used as an Interchange Schedule in the CAISO Energy Management System calculation of Area Control Error and the integrated value of which is treated as an Interchange Schedule for Interchange accounting purposes."[39]

Like Pseudo-Ties, Dynamic Schedules are expected to be tagged at the average MW profile for each 15-minute interval of the next scheduling hour as a single hourly value. These E-Tags must be submitted at least 20 minutes before the operating hour, and the transmission profile (described below) should reflect the expected maximum MW usage, for the Dynamic Schedule, for the hour. If the Dynamic Schedule or Pseudo-Tie is providing or bidding ancillary services the E-Tag must be submitted by 40 minutes before the operating hour.

Pursuant to NERC reliability standards and WECC Criterion, E-Tags for Dynamics Schedules also must be updated in certain circumstances:

---

[38] *See generally, CAISO*, 136 FERC ¶ 61,239 at P 2 (2011).
[39] Appendix A to the ISO tariff.

- Where the average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±10%.
- Where the average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ±25 megawatt-hours.
- Where the Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.
- Each hour of a dynamic schedule with the actual value within 60 minutes of the completion of the operating hour to allow for correct Net Scheduled Interchange between BAs.

In any case, the Energy profile of the Dynamic Schedule must be updated with the final integrated Energy amount (MWh), as predetermined by a single, agreed-upon source, within 60 minutes after the completion of the Operating Hour.

Purchasing-Selling Entities/Scheduling Coordinators also must monitor Dynamic Schedule E-Tags for reliability curtailments and make adjustments to the dynamic signal accordingly. After a reliability curtailment has been initiated and subsequently released, they must release the reliability limit profile on the appropriate E-Tag at the time the reliability event allows for the reloading of the transaction, and without releasing the reliability limit of other Balancing Authorities and Transmission Service Providers. The existing level on the Interchange transaction E-Tag must not be greater than the most limiting reliability limit.

8.3   E-Tag Tools

The Western Interchange Tool (WIT) or successor electronic confirmation tool serves as the E-Tag authority in the WECC. The WIT is treated as the final record of Net Scheduled Interchange (NSI) and Net Actual Interchange (NAI) under normal operating conditions. In accordance with NERC standards, WIT receives requests for interchange (RFIs) via E-Tags from various entities and distributes these requests to reliability entities (balancing authorities and transmission service providers) and market entities for reliability and market assessments. WIT also confirms requests for interchange based on criteria set forth in NERC and WECC standards.

The ISO validates interchange transactions and confirms them with adjacent balancing authorities prior to implementing them as scheduled interchange. Additionally, the ISO assesses interchange transactions for reliability purposes, adequacy of transmission rights, and

ensures market awards are not exceeded prior to E-Tag implementation. The ISO uses the interchange transaction scheduling software to process E-Tags, and when necessary, curtails/adjusts or denies E-Tags that do meet requirements.

The interchange transaction scheduler manages interchange transactions, provides Net Scheduled Interchange (NSI) to the ISO's energy management system (EMS) and real-time market. The interchange transaction scheduler also facilitates hourly NSI and Net Actual Interchange (NAI) checkout with adjacent Balancing Authorities (BA). In plain terms, the interchange transaction scheduler informs each balancing authority's systems on the expected net energy transfers across the interties. The individual and aggregate NSIs for each hour is based upon validated E-Tags.

8.4   What goes into an E-Tag?

This BPM cannot provide an exhaustive guide to submit E-Tags. Specific E-Tag requirements are subject to national (NERC and NAESB) and regional (WECC) standards, in addition to specific ISO requirements. Scheduling Coordinators seeking to schedule across interties should consult the following sources (as they are required to comply with them):

- NERC INT Reliability Standards
- WECC INT Regional Criterion
- NASEB Wholesale Electric Quadrant Standards
- NAESB Electronic Tagging Functional Specification
- ISO Operating Procedure 2510 (NERC Tagging Requirements)
- ISO Operating Procedure 2510A POR/POD Scheduling Path Cross Reference
- ISO Operating Procedure 4410 Emergency Assistance
- ISO Operating Procedure 4410D Emergency Assistance Resource IDs

While these sources comprehensively describe E-Tag requirements, generally the following information or headings appear on a typical E-Tag:

a) Tag Info: provides information about the Generator Control Area (GCA), the Purchasing Selling Entity (PSE), the tag code, the Load Control Area (LCA), the tag type (Transaction Type), the Time Zone of the tag, and MWh at the generation plant and at the destination load.

b) Market Path: provides information about the PSE, the Product, the Contract, and a Miscellaneous Information (Misc Info) field.

c) Physical Path: provides information on the proxy path of the power flow from the source Balancing Authority (BA) to the destination (sink) BA. This part of the tag includes information on the Transmission Service Provider (TSP), the Market Operator (MO), the Purchasing Selling Entity (PSE), the Point of Receipt (POR), the Point of Delivery (POD), the Scheduling Entities (SE), Contract if any, Miscellaneous Information (Misc Info) field and Loss columns.

d) Transmission Allocation: provides information about the TSP, the Owner, the Product, the OASIS information, NITS Resource, and Misc info field.

e) Transmission profile: provides information about the MW capacity amount of transmission reserved for the tagged transaction.

f) Energy profile: provides information about the MW amount of energy.

g) Loss Accounting: provides loss accounting

h) Carbon Copy List: provides a location for any entity to be copied on the E-Tag. Generally FERC is in this field.

i) Approval Status History: for the selected Request or all Requests if you are in the current state of the E-Tag. Provides information regarding the entities that took action on the creation of and changes on the E-Tag with a reason/comment. It also shows the exact time the action was initiated and what type of change took place. This is primarily automated.

j) Request Status: provides information on requests status and the timeline of each request.

k) Approval Status: provides the Approval Status History for all Requests in a single view and includes Timing information.

8.4.1   Valid Transmission and Energy Profiles

The E-Tag transmission profile is what the market participant has reserved, not necessarily the ISO transmission capacity the ISO market has awarded. The ISO market award is the transmission reservation the ISO market has awarded the SC on the intertie to transfer its energy. The MW value in the energy profile should equal the ISO market award and should not exceed the total MW value in the transmission profile.

The energy profile is the actual, expected MW value the market participant intends to flow, deliver, or receive. The energy profile should never be greater than the transmission profile

because the market participant cannot flow more energy than they have reserved on the intertie. The energy profile should always be lower than or equal to the transmission profile. Scheduling Coordinators for dynamic resources and pseudo-tied generating units should avoid perfunctorily "maxing out" energy profiles to equal their transmission profiles or their generators' PMax. Doing so creates an unnecessary reservation on the interties that can present or exacerbate reliability and market issues. Energy profiles should always equal the resources' actual expected energy during the relevant interval.

Scheduling Coordinators also must update energy profiles on Dynamic and Psuedo-Ties after the relevant trading hour to equal the actual energy flow in MWh.[40] The PSE/Scheduling Coordinator E-Tags all dynamic schedules at the expected average MW profile for each 15 minute interval of the next scheduling hour, and then the PSE/Scheduling Coordinator updates the E-Tag with the actual value within 60 minutes of the completion of the operating hour. Section 1.5.6 of Appendix M of the ISO tariff reiterates this requirement, stating that a dynamic signal must be integrated over time by the Host Balancing Authority Area for every operating hour. All of these requirements are consistent with the most recent NAESB E-Tagging functional specifications.

8.4.2   Capacity Profile for Ancillary Services

Capacity E-Tags are treated differently than energy tags. Capacity tags have a valid transmission profile; however unlike energy E-Tags, capacity E-Tags do not have energy profiles until dispatched for energy in real time. Following the dispatch of capacity to energy the PSE/SC must immediately update the energy profile on the E-Tag to reflect the energy dispatch.

8.4.3   Scheduling Paths

The ISO market scheduling paths are associated with the market scheduling and intertie points. In most cases, the name registered in the NAESB Electric Industry Registry (EIR) provided by the OATI web Registry system is the same as the intertie point. WECC tagging specifications require a single point to be designated as point of receipt or delivery on E-Tags.[41]

8.4.4   Static Schedules or Normal E-Tags

For static schedules on normal type E-Tags a separate E-Tag must be submitted for each type of market award for energy, spin, or non-spin. Separate tags must be made for each of these product types to facilitate validation of tagged interchange with the respective market awards for energy, spinning reserves or non-spinning reserves. While a single market resource ID may be

---

[41] See https://www.naesbwry.oati.com/cgi-bin/webplus.dll?script=/NAESBWRY/sys-main.wml.

used to bid multiple market products into the ISO market on the interties, separate E-Tags are required to facilitate the validation process. The ISO's Interchange transaction scheduler compares the product type shown on the E-Tag, in the CAISO_PRODUCT Token/Value pair (ENGY, SPIN, or NSPN) with ISO market awards to validate each e-Tagged Interchange schedule. Only one product can appear on each E-Tag.[42]

When using a single Resource ID to schedule use of more than one type of transmission (for example use of both Energy Bid Curve and contract rights using a Contract Reference Number (CRN)), each transmission award must be separately tagged.[43] This situation can occur if energy is awarded to both an energy bid and the ETC, TOR, or CVR self-schedule with the MW allocation using a single resource ID. The responsible scheduling coordinator must submit two E-Tags, one for the energy bid award and one for the ETC/TOR/CVR award, each with the same resource ID.

8.5   Tagging and Validation Timelines

8.5.1   Tagging Validation and CAISO Market Awards

Approving an E-Tag does not guarantee a market award. In other words, there is not a causal relationship between interchange validation and market awards. E-Tag approval by the ISO guarantees neither an ISO market award nor a transmission reservation in the ISO BAA. All market import or export interchange schedules are subject to final approval and transmission allocation in the ISO markets.

Moreover, all interchange schedules are subject to approval by adjacent BAs and transmission providers. The interchange scheduler may curtail E-Tags due to reliability reasons or for violation of NERC, NAESB, WECC, or ISO/BAA E-Tag requirements. Invalid E-Tags generally will be curtailed/adjusted to zero or denied.

Prior to the expiration of the reliability assessment period as defined in timing requirement tables in NERC Standard INT-006-4, the ISO will respond to each on-time arranged interchange, emergency arranged interchange, and reliability adjustment arranged interchange to transition an arranged interchange to a confirmed interchange. If a reliability adjustment of

---

[42] see the *Allowable Tag and Market Award Combinations* table at
https://www.caiso.com/Documents/AllowableTag_MarketAwardCombinations.pdf. .

[43] System resources are selected from the drop-down menu in SIBR. They include, for example, resources with RA obligations, ETC/TOC contracts, certified to provide ancillary services, IBAA agreements for transmission loss adjustment, specific resource IDs, recirculating resource ID, losses, inadvertent payback, emergency assistance, MSS load following, and EIM transfer schedules.

arranged interchange is denied by the ISO, the ISO must notify the reliability coordinator within 10 minutes after the denial.[44]

If a reliability coordinator directs the modification of a confirmed interchange or implemented interchange for actual or anticipated reliability reasons, a reliability adjustment of the arranged interchange schedule must be submitted within 60 minutes of the start of the modification. Also, if a reliability coordinator directs the scheduling of interchange for actual or anticipated reliability reasons, an E-Tag must be submitted within 60 minutes of the start of the interchange schedule.

8.5.1.1 Day-Ahead and Real Time

It is highly recommended that Scheduling Coordinators tag their ISO Day Ahead RUC energy and IFM AS market awards following the publishing of the Day Ahead market results. If for any reason the ISO HASP market advisory dispatch fails, the market participant is required to supply their RUC energy and ancillary service awards.

Tagging your ISO DA RUC market award to allow E-Tags to be approved or denied by the ISO also allows any issue on the E-Tag to be reviewed and fixed before real time. The ISO is required to act on each E-Tag upon submittal. According to the NERC INT-006-4 requirement: "Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined . . . ."

8.5.2 When to submit E-Tags

Upon receiving an ISO real time market award on an intertie, the Scheduling Coordinator must submit an E-Tag to schedule the delivery of the energy or capacity award.

In addition to complying with all generally applicable E-Tagging requirements, Scheduling Coordinators must submit their E-tags consistent with the requirements specified in Section 30.6.2 of the ISO tariff. If a Scheduling Coordinator receives an intra-hour Schedule change, then the Scheduling Coordinator must, by twenty minutes before the start of the FMM interval to which the Schedule change applies, ensure that an updated energy profile reflects the change. Please see section *7.2.2.1 E-Tagging Timelines and Rules* for explicit FMM tagging instructions.

---

[44] These terms are defined by NERC and used throughout the industry. They are not defined terms under the ISO tariff. NERC defines Arranged Interchange as "The state where a Request for Interchange (initial or revised) has been submitted for approval;" Confirmed Interchange as "The state where no party has denied and all required parties have approved the Arranged Interchange;" Reliability Adjustment Arranged Interchange as "A request to modify a Confirmed Interchange or Implemented Interchange for reliability purposes;" Emergency as "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System;" Implemented Interchange as "The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation." *See* http://www.nerc.com/files/glossary_of_terms.pdf.

Without limitation, and as further detailed in section 30.6 of the ISO tariff, Scheduling Coordinators must submit E-Tags 20 minutes prior to the applicable Trading Interval for the following:

- Self-scheduled hourly block
- Self-scheduled Variable Energy Resource
- Economic hourly block bid
- Economic hourly block single change bid

For Fifteen minute market economic bid, if there is no e-tag and hence no transmission profile available in the market before the FMM run that starts at T-37.5, the FMM process will limit the FMM bid in that upcoming fifteen-minute market run to 0 MW because there is no transmission profile provided to the CAISO to support that fifteen minute bid. In addition, if the Scheduling Coordinator intends to limit its participation in the FMM to the quantity in the HASP advisory energy schedule (including zero), the Scheduling Coordinator may update its transmission profile to the maximum amount it wants to make available to the FMM prior to the start of the binding FMM optimization mentioned above. If the Scheduling Coordinator does not have a transmission profile greater than or equal to its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed amounts greater than what is listed in the transmission profile. FMM and AS awards are limited to the lesser of bid or transmission profile.

Absent extenuating circumstances, the ISO automatically updates energy profiles on E-Tags for energy schedules that change from HASP to the FMM within a Trading Hour. In performing this service for a Scheduling Coordinator, the ISO does not assume any responsibility for compliance with any E-Tag requirements or obligations to which the Scheduling Coordinator is subject. The changed energy profile will apply for the balance of the operating hour unless it is subsequently changed by a further updated energy profile.

8.5.3   EIM Transfers

EIM transfers are called Energy Transfer System Resources (ETSRs). They can be static (15 min resources on normal type E-Tags) or dynamic (5 min resources on dynamic type E-Tags). Please see the *BPM for Energy Imbalance Market* for further details.

8.6   Emergency and Contingency Events

During emergency conditions, specific emergency intertie resources are pre-registered in the ISO Master File to record transfer of the energy. Please see ISO Operating Procedure 4410D, Emergency Assistance Resource IDs for the pre-registered emergency resource IDs. The tagging must be done following the tagging rules outlined in ISO Operating Procedure 4410,

Emergency Assistance. Contingency events are not any different when it comes to the market awards and tagging ISO market awards requirements. In accordance with reliability standards, the ISO and all balancing authorities will either approve or deny arranged interchange requests received based upon reliability considerations. Additionally balancing authorities will implement confirmed interchange received, and sending and receiving balancing authorities will agree to interchange prior to implementing it in their ACE equation.

The emergency type tag shall only be used for E-Tags at the request of the Interchange Scheduler or in response to an operational message from the ISO. The ISO may request use of an emergency E-Tag type in the event an import or export schedule is required after normal scheduling timelines and the transaction is in response to a loss of transmission facility, potential reserve or energy deficiency, or to supply or receive emergency assistance from another BAA during a contingency event. The emergency type tag is not used nor requested by the ISO for economic purposes or to expedite approval for a market transaction or for a late E-Tag under non-emergency or non-potential emergency events. Emergency type E-Tags will not be approved by the ISO outside of an emergency or potential emergency event.

8.7   Ancillary Services

Providing ancillary services across the interties requires an E-Tag as well. After certification, scheduling coordinators may bid and be awarded spin, non-spin and regulation across the interties in the day-ahead market or in real-time during HASP and FMM.

For ancillary service static awards, a capacity type E-Tag must be used and the energy profile in the E-Tag should be zero. When energy is actually dispatched and delivered the E-Tag shall be updated at that time, with the dispatched amount.

For ancillary service dynamic awards, a dynamic type E-Tag must be used. If the dynamic resource has an energy award, that MW value should be in the energy profile. The dynamic transmission profile should be no less than the total MW value of the bids submitted for energy and ancillary services (Total market awards for the dynamic and pseudo tie resources will be limited by the transmission profile on the E-Tag(s).). If the awarded capacity is dispatched as energy then the dynamic E-Tag energy profile shall be updated within 60 minutes after the hour is over to reflect the final integrated quantity of energy delivered, inclusive of both awarded energy and ancillary service dispatched energy. A single dynamic or pseudo type tag may be used for energy and ancillary services for dynamic and pseudo tie resources.

Ancillary service awards require firm transmission on all line segments on the transmission allocation section of the E-Tag. This requirement applies to both static and dynamic transfers. For detailed instructions on tagging ancillary services, consult Operating Procedure 2510.

8.9.   Post Market Activities

Welcome to the *Post Market Activities* section of the CAISO *BPM for Market Operations*. In this section, you will the find the following information.

➤ How CAISO validates LMPs

➤ How CAISO applies administrative prices

8.19.1   Price Validation

The CAISO has authority under the MRTU Tariff, to correct prices to ensure that settlement is consistent with the Tariff. CAISO shall make reasonable efforts to ensure that LMPs published to OASIS and through the Customer Market Results Interface (CMRI), and ultimately used for settlement and billing, are calculated accurately and reflect all pertinent operational data and system conditions, and are consistent with CAISO Tariff provisions. CAISO shall continuously monitor all market clearing software solutions to identify anomalous resource commitment, dispatch levels, and prices that may have resulted from erroneous input data and/or hardware/software failure of the market applications. All markets in Day-Ahead and Real-Time shall be subject to this Market Validation process. Although the CAISO will make every effort to validate market clearing processes and results prior to publication of results, this will not always be the case, particularly for Real-Time markets.

This market validation effort can be viewed as a two phase process:

➤ Phase I: Market Validation

There is a small window of opportunity to validate the market results before they are published to OASIS and CMRI. This window is different for each market. The Day-Ahead Market allows more time to validate market outcomes before publishing results. Thus, CAISO expects that invalid Day-Ahead Market result publication to OASIS and CMRI would be unlikely. On the other hand, for the Real-Time Market, the 5-minute dispatch interval timeline provides CAISO analysis limited opportunity to identify and resolve invalid market data or solutions before publication of the invalid market prices. In either case, when prices are determined to be invalid after they are published to OASIS, they would be corrected following the price correction process described below.

➤ Phase II: Price Corrections

The price correction process is an off-line analysis that occurs after the Market results are published to OASIS and sent to Market Participants through the CMRI.

The purpose of the validation is to identify and correct prices in any periods with error conditions or incorrect results. The price validation process ensures that the LMPs used for Market Settlement are based on the proper data, and that the Market solution accurately reflects the power system conditions and CAISO Operator actions that should have been considered in the relevant Market process. This post-publication market validation process is completed within a prescribed window of time following each market. All prices published on OASIS or in other sources are subject to potential correction during the prescribed price correction window. All prices are considered final after the prescribed price correction window has expired.

8.1.19.1.1   Market Validation

For all CAISO Markets, CAISO shall closely monitor results, and if time permits, correct problems and re-run the market as necessary to minimize the number of post-publication price corrections.   The short timeline of the Real-Time Market may prevent the re-running of the market for the current interval in most cases, but correcting any issues immediately serves to minimize the number of intervals affected by the problem going forward, and thus minimize the post-publication price corrections.

8.1.29.1.2   General Scope of Price Corrections

Prices may be corrected when (i) a market solution is determined to be invalid, or (ii) invalid prices are identified in an otherwise valid market solution. The following are some reasons that may be the causes of these conditions:

➢ Data Input failure. Missing or incorrect versions of one or more data elements input to the market applications may result in an invalid market solution and/or prices. State Estimator data, in particular, may be a cause of Real-Time Market validation problems, and will be a focus of the validation effort.

➢ Hardware/Software failure. While CAISO has designed a very high degree of reliability into the CAISO Market systems' architecture, the market run may fail to yield a converged solution in all executions. This may be due to hardware or software failure, planned market systems outages, or simply a failure of the Security Constrained Unit Commitment (SCUC) optimization software to converge. In any case, such events result in an invalid or non-existent market solution, for which corrected prices will be determined after-the-fact, per Section 8.1.4 below.

➢ Inconsistency with Tariff. A third category of invalid market solution or incorrect price calculations is related to the correct application of market rules, per CAISO Tariff. Market results will be validated to be consistent with CAISO Tariff, and where applicable,

prices may be corrected to meet this goal. This includes, but is not limited to ensuring that (i) price setting resources are eligible to do so, and (ii) binding constraints are applied (or relaxed) in the appropriate priority order.

Section 35.3 of CAISO Tariff provides additional details regarding the basis for price corrections.

Following are some qualifications to the scope of price corrections:

➢ Price anomalies, or price spikes, due to scarcity of resource bids will not be a cause for price corrections.

➢ The extent to which bids are mitigated in the MPM process has a direct impact on the market clearing prices in the IFM or RTM. Therefore, these SCUC solutions will be subject to market validation principles. However, it should be noted that prices resulting from the MPM SCUC passes are not themselves validated, as these prices are not used for settlement.

➢ Advisory HASP prices are not in scope for price correction.

➢ Prices for Exceptional Dispatch instructions will not be subject to the price correction framework, as they will not be the output of the market engine.

➢ Hourly weighted average LMP's and 10-minute settlement prices will be corrected, as applicable, when 5-minute RTED prices are corrected. These prices are not directly subject to the price correction process, but will remain synchronized with the validated 5-minute prices as they are systematically derived by the corrected 5-minute prices.

➢ If CAISO corrects a PNode price, it will update the corresponding LAP / Trading Hub prices accordingly.

8.1.39.1.3   Scope of Price Corrections for DAM

The CAISO will validate all commitment decisions, dispatch levels, and prices to be consistent with bids, market rules, and system conditions. In this validation process, the CAISO will evaluate the integrity of all market inputs and results. When a market solution is determined to be invalid, prices will be corrected as necessary, and the affected public market information re-posted to OASIS.

Specifically, the following elements are in scope for the Day-Ahead Market price corrections:

➢ Final Hourly LMPs for all Pricing Nodes (PNode) and Aggregated Pricing Nodes (APNode)

➢ Marginal energy cost component

➢ Marginal congestion cost component

➢ Marginal loss cost component

➢ Final Hourly ASMPs for all PNodes

➢ Final hourly transmission constraint shadow prices at each transmission interface

8.1.49.1.4   Scope of Price Corrections for RTM

Specifically, the following elements are in scope for RTM price corrections:

➢ <u>Binding FMM Prices</u>. 15-minute binding LMPs, ASMPs, and transmission constraint shadow prices, including each of the three cost components, are subject to the price correction process.

➢ <u>Real Time Economic Dispatch</u>. 5-minute binding LMPs, including each of the three cost components, for all PNodes and APNodes are subject to the price correction process.

➢ <u>Transmission and Intertie constraint shadow prices</u>. 5-minute transmission constraint shadow prices at each transmission interface will be validated and subject to price correction.

8.1.59.1.5   Price Correction Process

The price correction process starts with a validation of all prices indicated above in Sections 8.1.3 and 8.1.4 for a given Trading Day, beginning immediately after prices are available, and ending after the Price Correction Time Horizon (defined in section 8.1.6.2, below) has closed for that Trading Day to identify if any corrections are necessary. The intent of the validation process is to ensure appropriate and accurate inputs are used in Settlements as well as to ensure prices accurately reflect system conditions.

Where feasible and practical, the CAISO will correct invalid prices to conform to the relevant CAISO Tariff provisions. Where this is neither feasible nor practical, the CAISO will correct prices as close as reasonably possible to the price that should have resulted under the CAISO Tariff provisions, using the most accurate data available, and in a manner that is consistent with

the prevalent system conditions at that time. The CAISO will use one of the following methods, as appropriate, with respect to the nature of the invalid price conditions.

The order of the price correction methods listed below are shown in order of preference from most preferred to least preferred. When correction of prices can be done on isolated pricing locations or resources without impacting the over-all market solution, this method is preferred. If this is not possible, the preferred price correction method is to re-run the affected markets, with the root cause of the invalidation corrected. However, this may not always be feasible due to unrecoverable data loss, or may not always be practical within the Price Correction Time Horizon. In these situations, interval or solution replication will be used.

8.1.5.19.1.5.1 Isolated Price Corrections

When possible, the CAISO will selectively recalculate invalid PNode and APNode prices, such that the market optimization need not be re-run. This method can only be used when invalid prices are isolated and when corrections can be made such that no other market clearing prices are affected by the correction.

8.1.5.29.1.5.2 Market Re-Runs

A market solution may be determined to be wholly invalid because of hardware or software failure, incorrect data or solution parameters, or any other factor that affects system wide results. When such a market solution is identified, the CAISO will attempt to recreate a valid SCUC solution for the affected market run. When the source of the problem is incorrect data, the market re-run will use as much validated data as possible from the original market run. To replace the problematic data, CAISO will either (i) restore the correct data when possible, or (ii) recreate or replicate data using the best available alternate data sources.

8.1.5.39.1.5.3 Replicate Prices from Validated Market Intervals – Day-Ahead Market

If the entire market solution is deemed to be invalid then all prices will be corrected using the re-run method specified above. In no cases will an invalidated Day-Ahead Market solution be replaced with a valid Day-Ahead Market solution from a previous Trading Day.

Interval replication shall only apply in Day-Ahead Market when some but not all hourly intervals within a valid market run are deemed to be invalid and the market is not rerun as explained above. This condition is expected to be rare. In such a case, prices for an invalidated interval shall be replicated from prices for a validated interval that best represents the market conditions in the invalid interval. This will be an adjacent interval in most cases.

8.1.5.49.1.5.4 Replicate Prices from Validated Market Intervals – Real-Time Market

Price replication in Real-Time Markets will only be under taken when both isolated price correction and market re-run actions are (i) not feasible because of CAISO's inability to generate a reasonably accurate set of input data or the security constrained unit-commitment or security constrained economic dispatch processes cannot find a feasible solution, or (ii) not practical from the perspective of validating all prices within the Price Correction Time Horizon.

For the source of replicated prices, the CAISO may use prices from validated intervals within the same market solution, similar to that which is described above or prices from a previous or subsequent market solution. When prices are replicated from a previous or subsequent market solution, the replicated prices may be either binding or advisory prices. The selection of the source market solution and specific interval for price replication shall be based on the best representation of the market conditions for the invalidated interval.

The following are some details of the RTM price replication methodology:

➢ For RTED (including RTCD) FMM energy prices, FMM, ASMP, and FMM flexible ramping constraint shadow prices source market intervals for price replication shall be taken from a market solution within the same Trading Hour as the invalid market interval for bid consistency, when possible. If this is not possible the analyst will replicate prices from an interval in an adjacent Trading Hour that best resembles the market conditions of the invalidated market run.

➢ For Short Term Unit Commitment (STUC), the advisory prices for 15-minute intervals are not in-scope for price corrections.

➢ For RTED, prices may be replicated from the most representative market solution, and may be from a similar RTED market run including advisory solution for the same time interval from previous RTED runs, or from a similar 15-minute FMM run.

8.1.69.1.6   Procedures

8.1.6.19.1.6.1 Publication

All prices published to OASIS and reported to Market Participants through CMRI are considered provisional until the validation and Price Correction Time Horizon is completed. If a price correction is needed for a particular trade day and that correction cannot be made within the prescribed Price Correction Time Horizon due to processing and publication issues then the CAISO shall provide notice to market participants through OASIS about the delay of the processing and publication of corrected prices.

8.1.6.29.1.6.2 Price Correction Time Horizon

The CAISO will begin validating market prices immediately upon publication of results for all market runs. The price validation process for a given Trading Day will conclude in a number of days after the Trading Day, as described below. The period between the end of the Trading Day and the end of the price validation process is called the Price Correction Time Horizon. All prices for a given Trading Day are subject to validation and possible price correction until such time as (i) the Price Correction Time Horizon has ended for that Trading Day, or (ii) CAISO has published a notice to its website that the validation process for the Trading Day is concluded.

The CAISO will inform the market through an OASIS message about price corrections as soon as practical within the proposed three business day window for the day-ahead market and the five business days for the real time market. If such notice is not published on OASIS before the end of the Price Correction Time Horizon for a Trading Day, then such notice is implied by the expiration of the Price Correction Time Horizon, and no further validation or price corrections will occur for the Trading Day. The CAISO will not make any price corrections after the Price Correction Time Horizon has expired except as otherwise directed by the Federal Energy Regulatory Commission.

The CAISO will evaluate the length of the Price Correction Time Horizon annually.

> ➤ The Price Correction Time Horizon is three business days for the Day Ahead Market, and five business days for Real-Time Market, meaning that the Price Correction Time Horizon shall begin at the time of publication of market prices to OASIS for the Trading Day, and shall end at 23:59 on the third or fifth business day, as applicable following that Trading Day.

In the event that the CAISO experiences a processing or publication issue which renders the prices posted on OASIS or CMRI inconsistent with any price that was subject to a price correction, the ISO shall endeavor to correct such publication as soon as practicable. Twenty business days after the applicable Trading Day, the CAISO will not correct such processing or publication errors except as otherwise directed by the Federal Energy Regulatory Commission. After twenty business days, if there is still a discrepancy between the published prices on OASIS or CMRI and the prices used for settlements, in the event of a valid settlement dispute the CAISO will adjust the settlement prices to reflect the prices posted on OASIS for the applicable intervals.

8.1.6.39.1.6.3 Reporting

All price corrections within a week shall be summarized in a report and published on the CAISO website. This report shall be published on the CAISO website no later than the seventh calendar

day following the completion of the price correction process for all Trade Days within the stated week, defined from Monday to Sunday. For each instance of market price correction, the weekly report shall contain:

➢ Brief description of the root cause of market invalidation

➢ Market intervals that were affected

➢ Price locations that were affected

➢ Method of Price Corrective action(s) taken

For illustrative purposes a sample of the timeline for generating the weekly price correction report is noted below. In the table below we have included the final trade days under the T+5C criteria as well as the first few weeks under the new Price Correction Time Horizon. The first column reflects the actual calendar day on which particular price corrections are due. The third column shows which trade days will be corrected under the T+5C time frame. The fourth and fifth columns show the trade days to be corrected under the T+3B and T+5B time frame. The last column shows the time period that will be covered on the respective price correction report. Using the first week, March 31 through April 6 as an example, the weekly price correction report for the price corrections that were made during that week would be published no later than April 13, 2014. That weekly price correction report would include T+5C trade days, March 26 through March 31, and IFM T+3B trade day, April 1.

Calendar Date	Day	T+5C	IFM Trade Dates (T+3B)	RT Trade Dates (T+5B)	Weekly Price Correction Report Period
31-Mar-14	Monday	3/26/2014			
01-Apr-14	Tuesday	3/27/2014			
02-Apr-14	Wednesday	3/28/2014			
03-Apr-14	Thursday	3/29/2014			
04-Apr-14	Friday	3/30/2014	4/1/2014		
05-Apr-14	Saturday	3/31/2014			
06-Apr-14	Sunday				All Trade Days to become current with new timeline
07-Apr-14	Monday		4/2/2014		
08-Apr-14	Tuesday		4/3/2014	4/1/2014	
09-Apr-14	Wednesday		4/4 - 4/6/2014	4/2/2014	
10-Apr-14	Thursday		4/7/2014	4/3/2014	
11-Apr-14	Friday		4/8/2014	4/4 - 4/6/2014	

12-Apr-14	Saturday				
13-Apr-14	Sunday				3/31 - 4/6/2014
14-Apr-14	Monday		4/9/2014	4/7/2014	
15-Apr-14	Tuesday		4/10/2014	4/8/2014	
16-Apr-14	Wednesday		4/11 - 4/13/2014	4/9/2014	
17-Apr-14	Thursday		4/14/2014	4/10/2014	
18-Apr-14	Friday		4/15/2014	4/11 - 4/13/2014	
19-Apr-14	Saturday				
20-Apr-14	Sunday				4/7 - 4/13/2014
21-Apr-14	Monday		4/16/2014	4/14/2014	
22-Apr-14	Tuesday		4/17/2014	4/15/2014	
23-Apr-14	Wednesday		4/18 - 4/20/2014	4/16/2014	
24-Apr-14	Thursday		4/21/2014	4/17/2014	
25-Apr-14	Friday		4/22/2014	4/18 - 4/20/2014	
26-Apr-14	Saturday				
27-Apr-14	Sunday				4/14 - 4/20/2014

The weekly report will not contain "before and after" data for price corrections. Once invalid prices are replaced with corrected prices on OASIS, the old invalid prices are no longer relevant and will not be made available. Note that OASIS does provide data versioning functionality which allows Market Participants to identify which data points have been updated during the price correction process, and also can be set to notify Market Participants upon updates to data therein.

8.29.2   Administrative Pricing

The CAISO has authority under the CAISO Tariff, to apply administrative prices under certain conditions. The administrative pricing implementation in the CAISO markets uses a tiered approach depending on the market and the length of the disruption period. The CAISO experiences minor market disruptions in the real-time market due to software maintenance (such as database updates and software releases) or unexpected software issues, and these occur under both normal and non-emergency situations. The CAISO can also intervene in the CAISO markets during system emergencies or to prevent system emergencies, and suspend or disrupt the market and operate the system manually. The administrative pricing can apply to any market or product, including the day-ahead market, fifteen- and five-minute markets.

8.2.19.2.1   Administrative Pricing for Day-Ahead Market

The target publication time for the day-ahead market is 1:00 p.m. The CAISO generally is able to publish on time, but in some scenarios it may delay the publication of results to resolve a specific issue. This usually may require a late publication that is not far from the ideal time. However, in the extreme case where the CAISO has not published the day-ahead market results or determines it may suspend the day-ahead market, it will notify market participants by 6:00 p.m. of the CAISO decision. The notification to the market will be through a market notice, and will be in addition to any updates provided through the operational messages during the course of the event. This approach is to provide market participants with the best available information by 6:00 p.m., including whether the CAISO anticipates that it will be able to publish market results. This will allow market participants to know their schedules and have enough lead time to meet their resource commitment instructions with sufficient advance notice. In cases where commitments and dispatches are not feasible to happen by the time the day-ahead results are published, the ISO may be required to use exceptional dispatches. The alternatives that the CAISO can use are:

(i)   **Late publication of the day-ahead market results**: If the CAISO has addressed the issues causing the problem, the CAISO will inform market participants of its decision and the likely time-frame for publication. The CAISO's preference will be to publish the day-ahead market for the day even if it is a late publication because ti will be the most accurate solution.

(ii)   **Use the previous day's market results for the day-ahead market**. There are several reasons why this can be a workable alternative in the event the CAISO day-ahead market results are not available. First, using the previous day's market results will mitigate against the worst-case scenario in which the real-time market might also need to be suspended. Second, using the previous day's market results will provide the CAISO with a starting point for dispatch and settlement, while the real-time market can provide the incremental or decremental differences between the day-ahead and the real-time, thereby minimizing the need for the CAISO to issue manual dispatch instructions. Third, using the previous day's market results will allow market participants to know in advance their market results for the applicable trading day, which will minimize uncertainty and allow market participants to secure fuel and prepare their resources for unit commitment. Congestion revenue rights will settled as usual using prices from the previous day-ahead market because the energy market will still be settled at the day-ahead prices. However, if the CAISO decides to use the day-ahead market results from the previous day for the day-ahead market, it will

suspend any virtual bids for that day and settle only physical bids using the day-ahead market results from the previous day.

(iii)   **Rely solely on real-time market results and exceptional dispatch**. If the CAISO decides to rely solely on the results of the real-time market for pricing and settlement purposes, then there will be no virtual awards to settle. Congestion revenue rights will be settled on hourly prices estimated as the simple average of the four fifteen-minute market prices.

~~8.2.2~~9.2.2   Administrative Pricing for Real-Time Market

The administrative pricing logic is defined for both the fifteen- and five-minute markets. The rules for administrative pricing also depend on whether the real-time market is suspended or not. For conditions in which the market has not been suspended, the rules are defined based on the length of the disruption.

i) **Disruption lasting less than an hour**.
   a. If market results are unavailable for fewer than four consecutive 15-minute intervals in the fifteen minute market, the CAISO will use the fifteen-minute market prices, as applicable, for the fifteen-minute interval immediately preceding the fifteen minute market interval(s) for which fifteen minute market results are unavailable.
   b. If prices are unavailable for fewer than 12 consecutive five-minute dispatch intervals, the CAISO will use the real-time dispatch market prices, as applicable, for the dispatch interval immediately preceding the dispatch interval(s) for which market results are unavailable.

ii) **Disruption lasting an hour or longer in one of the two real-time markets**.
   a. If market results are unavailable for at least four consecutive fifteen-minute intervals in the fifteen minute market, but market results are available for the real-time dispatch during those fifteen-minute market intervals, the CAISO will use the average of real-time dispatch market results, as applicable, during each such fifteen minute market interval and use the market results as applicable from the prior intervals for which market results are unavailable as needed; and

   b. If market results are unavailable for at least 12 consecutive five-minute dispatch intervals, but market results are available for the fifteen minute market during those dispatch intervals, the CAISO will use the fifteen minute market results, as applicable, from the applicable fifteen minute market during the dispatch intervals

iii) **Disruption lasting an hour or longer for both the fifteen-minute market and the real-time dispatch**.

a. If market results are unavailable for at least four consecutive fifteen-minute intervals in the fifteen minute market and for the real-time dispatch during those fifteen-minute market intervals, the CAISO will use the day-ahead market results, as applicable, for the corresponding trading hour for which market results are unavailable; and

b. If market results are unavailable for at least 12 consecutive five-minute dispatch intervals and for the fifteen-minute market during those dispatch intervals, the CAISO will use the day-ahead market results, as applicable, for the corresponding trading hour for which market results are unavailable

Examples:

The following table illustrates two hours of the market with all prices available:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 1: five-minute prices are missing for five intervals as highlighted in the entries in yellow in the first table, per current logic, use last available five-minute price (green entry); this will result with the prices shown in the second table

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62						36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	62	62	62	62	62	36	38	39	44	43	43	48	50	55	57	59

Scenario 2: Both fifteen-minute and five-minute prices are missing, each one, for less than twelve and four intervals, respectively. Per current logic, CAISO uses the last available price for each market as shown in the second table:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50				40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65							36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	50	50	50	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	65	65	65	65	65	65	36	38	39	44	43	43	48	50	55	57	59

Scenario 3: If five-minute prices are missing for at least twelve intervals and fifteen-minute prices are available, then CAISO uses the fifteen-minute prices for the corresponding five-minute intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62															57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	50	50	51	51	51	40	40	40	45	45	45	39	39	39	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	51	40	40	40	45	45	45	39	39	39	53	53	53	60	57	59

Scenario 4: If fifteen-minute prices are missing for four or more intervals, then CAISO uses the simple average of the three five-minute prices for the corresponding intervals:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48																53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	60.6	60.6	60.6	62.3	62.3	62.3	57.6	57.6	57.6	36.3	36.3	36.3	42	42	42	53	53	53	60	60	60
RTD Price	44	46	47	47	70	65	65	62	60	59	59	55	35	36	38	39	44	43	43	48	50	55	57	59

Scenario 5: If both fifteen-minute and five-minute prices are missing for at least four and twelve intervals, respectively, then CAISO uses DAM prices for the trade hours corresponding to the RTM disruptions:

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50																			60	60
RTD Price	44	46	47	47																			57	59

Hour Ending	13												14											
FNM Interval	1	1	1	2	2	2	3	3	3	4	4	4	1	1	1	2	2	2	3	3	3	4	4	4
RTD Interval	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12
DAM Price	40												50											
FNM Price	48	48	48	50	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	60	60
RTD Price	44	46	47	47	40	40	40	40	40	40	40	40	50	50	50	50	50	50	50	50	50	50	57	59

There is also a specific rule for administrative pricing when the real-time market has been suspended. In such instances, the CAISO will use the previous day's day-ahead market results, as applicable, for the trading hour corresponding to the trading hour during which the real-time market has been suspended. Applying day-ahead market results in this manner will provide price certainty and transparency to market participants.

Finally, in the event administrative pricing logic does not apply in a given situation, the administrative price will be the price established for that product or service immediately prior to the disruption.

Addendum to Market Operations BPM (Based on Ver.45)

A   Addendum for changes

Due to Aliso Canyon ~~phase 2~~ gas-electric coordination initiative and the interim tariff revisions from December ~~1st~~16th, ~~2016~~ 2017 through ~~November 30, 2017~~December 16th, 2018. This Addendum will address the modification ~~to~~ based on Version 45 of the Market Operations BPM as follows;

Number

Number	Feature	Tariff Section	Effective Date	BPM section	Existing section in MO BPM	Modified section in MO BPM	Expiration Date
1	Make two-day ahead advisory schedules available with the clarification that they are not financially binding or operationally binding	6.5.2.2.3	6/2/2016	6.4.6, 6.7.4	See below	See below	~~November 30~~December 16th, ~~2017~~2018
5	Modifications to STUC so that STUC does not use Day-Ahead bids of resources not scheduled in day-ahead that do not have a real-time market must offer obligation	34.6 40.6.3	6/2/2016	7.7	See below	See below	~~November 30, 2017~~Made permanent
6	Introduce a constraint as needed into the CAISO's market processes to limit the affected gas area burn to a maximum or minimum	27.11	6/2/2016	6.6.5	See below	See below	~~November 30~~December 16th, ~~2017~~2018
7	Special tariff to deem selected constraints uncompetitive	39.7.2.2	6/2/2016	6.5.3	See below	See below	~~November 30~~December 16th, ~~2017~~2018
10	Clarification that it has authority to suspend virtual bidding in the event that the CAISO identified market inefficiencies	7.9.2 (d)	6/2/2016	2.5.2.4	See below	See below	~~November 30~~December 16th, ~~2017~~2018

A6.4.6   Publish Reports to Scheduling Coordinators

The following is a summary of the Day-Ahead reports available to SCs for online viewing after the DAM has completed its execution[45]:

  ➢ **Day-Ahead Generation Market Results** – Schedules of all generating resources.

  ➢ **Day-Ahead Load Market Results** – Schedules of both Participating Loads and Non-Participating Loads from the DAM.

  ➢ **Convergence Bid Clearing Results** – Virtual Supply Awards and Virtual Demand Awards from the IFM.

  ➢ **Day-Ahead RUC Capacity** – Incremental capacity amount committed or scheduled in the RUC, above the Day-Ahead Schedule.

  ➢ **Two Day**-Ahead Residual Unit Commitment (RUC) Advisory Schedules – Advisory RUC schedules produced from the second trade day of the two Day-Ahead market run.

  ➢ **Day-Ahead Import/Export Schedules** – Import and export Schedules from the DAM.

  ➢ **Day-Ahead Start-Up & Shutdown Instruction**s – Commitment instructions of all resources from the DAM.

  ➢ **Day-Ahead Ancillary Services Awards from accepted Bids and qualified Self-Provision** – Awards for AS MW quantity, by AS type and resource from the DAM.

  ➢ **Day-Ahead MPM Results** – Information about the "Mitigated" Bid that is used if the original Bid is modified in the MPM process. In addition the following MPM results will be published for informational purposes: LMPs at all PNodes and Apnodes with market resources associated with physical bids; shadow prices for all binding constraints; competitive path determination for all binding constraints; and reference bus identification.

  ➢ **Non-Participant Price Curves** – Information on the Default Energy Bids supplied by an independent entity used in MPM. Day-Ahead Inter-SC Trades – Inter-SC Trade schedules for both Inter-SC Trades at Aggregate Pricing Nodes and Physical Trades ,

---

[45] Note: the SC's confidential information is available only to the SC.

for both Inter-SC Trades of IFM Load Uplift Obligation and Ancillary Services from the DAM

➢ **Day-Ahead Resource Energy Prices –** Resource-specific (LMPs and ASMPs).

➢ **Day-Ahead Resource Ancillary Service Prices –** Resource- specific ASMPs.

➢ **Self-Provided AS Awards**.

➢ **Day-Ahead Unit Commitments** - Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market

➢ **Default RMR Minimum Load & Startup Cost Bid Curves** - Independent entity-supplied default Minimum Load and Start-Up cost bid curves used in the Market Power Mitigation process. This applies to RMR units only.

➢ **Day-Ahead LMPs at all Pnodes for informational purposes.**

➢ **Extremely Long-Start Resource Startup Instructions** - Startup instructions resulting from the Extremely Long-Start Commitment (ELC) process.

➢ **Day-Ahead Reliability Must Run (RMR) Dispatches** – RMR units that either have an energy schedule (from the IFM run) and / or an RMR dispatch

➢ **Conformed Dispatch Notice (CDN)** - Summary of the Day-Ahead Energy Schedules, Ancillary Service Awards, RMR Dispatches, Competitive Constraint Run results of RMR resources. This is available on CMRI.

➢ **Shadow prices for the interties –** Shadow prices for the interties are available in OASIS.

➢ **Volume of Virtual Awards** - System wide total Virtual Supply Awards and Virtual Demand Awards

➢ **Maximum MW limit per Eligible PNode and Eligible APNode** – Maximum nodal MW limit used to apply the Position Limits to Virtual Bid

➢ **Hourly Prices due to Convergence Bidding for CRR Adjustment Report –** Hourly LMP differentials between Day-Ahead Market and Real-Time Market used for CRR revenue adjustments caused by Virtual Bids under the CRR Settlement Rule.

> ➢ **Binding Transmission Constraints due to Convergence Bidding for CRR Adjustment Report –** Provides listing and status of PNodes associated with transmission constraints and whether their binding constraints were due to Virtual or physical Bidding activity in IFM. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

> ➢ **Flow Impact Due to Convergence Bidding for CRR Adjustment Report -** Reports hourly MW flow contributions for transmission constraints impacted by SCs submitting Virtual Bids on behalf of a Convergence Bidding Entity that is also a CRR Holder. This report provides support information for CRR revenue adjustments applied under the CRR Settlement Rule.

==Number 5==

A7.7   Short –Term Unit Commitment

This section is based on CAISO Tariff Section 34.6, Short-Term Unit Commitment.

At the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed, CAISO performs an approximately five-hour STUC run using SCUC and the CAISO Forecast of CAISO Demand to commit Medium Start Units and Short-Start Units with Start-Up Times greater than the Time Horizon covered by the FMM.

The Time Horizon (see Exhibit 7-1) for the STUC optimization run extends three hours beyond the Trading Hour for which the FMM optimization was run, and replicates the Bids used in that Trading Hour for these additional hours.

CAISO replicates Bids each time the hourly STUC is run by utilizing: (1) bids previously submitted in RTM by Scheduling Coordinator for that Trading Hour; or (2) the clean bid from the DAM if the resource has a Day-Ahead schedule or received a start-up instruction in RUC for the trading hour, or if the resource has a Real-Time must offer obligation for that trading hour. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run as a result of the Start-Up Time of the resource.

A Start-Up Instruction produced by STUC is considered advisory if it is not binding, i.e., when the resource can achieve its target Start-Up Time (as determined in the current STUC run) in a subsequent RTUC run based on its Start-Up Time. A Start-Up Instruction produced by STUC that results in a change in Commitment Status is issued after review and acceptance of the Start-Up Instruction by the CAISO Operator, in accordance with Section 6.3 of the CAISO Tariff.

The STUC only de-commits a resource to the extent that resource's physical characteristics allow it to be brought back online at the end of the Time Horizon. This requirement is needed because RTUC is unaware of future commitments that a resource may have beyond the Time Horizon.

STUC does not produce prices for Settlement. The STUC process only commits units needed for meeting Real Time imbalances. To the extent a unit is committed via STUC, a Start-Up instruction is provided to that resource (via ADS). Whether or not the resource is eligible for Start Up and Minimum Load Bid Cost Recovery is determined through a series of calculations described in the *BPM for Settlement and Billing, Section 12*.

Number 6

A6.6.5   Adjustment of Non-Priced Quantities in IFM

This section is based on CAISO Tariff Section 31.4, Uneconomic Adjustments in the IFM.

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point is subject to adjustments based on the scheduling priorities listed in Section 6.6.5.3.

Through this process, imports and exports may be reduced to zero, Demand Schedules may be reduced to zero, and Price Taker Demand (LAP Load) may be reduced. However, prior to reducing Load the following process is used to ensure that LAP Load is not reduced unnecessarily.

Market Parameter Values

This section provides the specific value settings for a set of ISO market parameters that are used for adjusting non-priced quantities in the market optimizations.

The parameter values are organized into three sections by market process: the Integrated Forward Market (IFM), the Residual Unit Commitment (RUC), and the Real Time Market (RTM). The parameters in these tables are also known in the jargon of mathematical optimization as "penalty factors," which are associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values in the tables for each market reflect the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software.

Integrated Forward Market (IFM) Parameter Values

Penalty Price Description	Scheduling Run Value[46]	Pricing Run Value	Comment
Market energy balance	6500	1000	Market energy balance is the requirement that total supply equal the sum of total demand plus losses for the entire system. In the IFM energy balance reflects the clearing of bid-in supply and demand; in the MPM component of the DAM it reflects the scheduling of bid-in supply against the ISO demand forecast.
Transmission constraints: Intertie scheduling	5000	1000	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply)	-6000	-150	The ISO considers transmission constraints when determining RMR scheduling requirements. After the ISO has determined the RMR scheduling requirements, the market optimization ensures that the designated capacity is scheduled in the market.
Pseudo-tie layoff energy	-6000	-150	Pseudo-tie layoff energy is scheduled under contractual arrangements with the Balancing Authority in whose area a pseudo-tie generator is located.

---

[46]   Penalty values are negatively valued for supply reduction and positively valued for demand reduction.

Penalty Price Description	Scheduling Run Value[46]	Pricing Run Value	Comment
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	5000	1000	In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Gas-burn nomogram	5000	1000	In the scheduling run, the market optimization enforces gas-burn constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Transmission Ownership Right (TOR) self schedule	5900, -5900	1000, -150	A TOR Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints.
Existing Transmission Contract (ETC) self schedule	5100 to 5900, -5100 to -5900	1000, -150	An ETC Self-Schedule will be honored in the market scheduling in preference to enforcing transmission constraints. The typical value is set at $5500, but different values from $5100 to $5900 are possible if the instructions to the ISO establish differential priorities among ETC rights. For some ETC rights the ISO may use values below the stated scheduling run range if that is required for consistency with the instructions provided to the ISO by the PTO.
Converted Right (CVR) self schedule	5500, -5500	1000, -150	A CVR Self-Schedule is assigned the same priority as the typical value for ETC Self-Schedules.
Ancillary Service Region Regulation-up and Regulation-down Minimum Requirements	2500	250	In the event of bid insufficiency, AS minimum requirements will be met in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
Ancillary Service Region Spin Minimum Requirements	2250	250	Spinning reserve minimum requirement is enforced with priority lower than regulation up minimum requirement in scheduling run.
Ancillary Service Region Non-Spin Minimum Requirements	2000	250	Non-spin reserve minimum requirement is enforced with priority lower than spin minimum requirement in scheduling run.

Penalty Price Description	Scheduling Run Value[46]	Pricing Run Value	Comment
Ancillary Service Region Maximum Limit on Upward Services	1500	250	In the event of multiple AS regional requirements having bid insufficiency, it is undesirable to have multiple constraints produce AS prices equaling multiples of the AS bid cap. An alternative way to enforce sub-regional AS requirements is to enforce a maximum AS requirement on other AS regions, thereby reducing the AS prices in the other regions without causing excessive AS prices in the sub-region with bid insufficiency.
Self-scheduled CAISO demand and self-scheduled exports using identified non-RA supply resource	1800	1000	Pursuant to section 31.4, the uneconomic bid price for self-scheduled demand in the scheduling run exceeds the uneconomic bid price for self-scheduled supply and self-scheduled exports not using identified non-RA supply resources.
Self-scheduled exports not using identified non-RA supply resource	1150	1000	The scheduling parameter for self-scheduled exports not using identified non-RA capacity is set below the parameter for generic self-schedules for demand.
Regulatory Must-Run and Must Take supply curtailment	-1350	-150	Regulatory must-run and must-take supply receive priority over generic self-schedules for supply resources.
Price-taker supply bids	-1100	-150	Generic self-schedules for supply receive higher priority than Economic Bids at the bid cap.
Conditionally qualified Regulation Up or Down self-provision	-405	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 received higher priority to maintaining the availability of regulation, over spinning and non-spinning reserve.
Conditionally qualified Spin self-provision	-400	NA	Conversion of AS self-schedules to Energy pursuant to section 31.3.1.3 receives higher priority to maintaining the availability of spinning reserve, over non-spinning reserve.
Conditionally qualified Non-Spin self-provision	-395	NA	This penalty price for conversion of self-provided non-spinning reserves balances the maintenance of AS self-schedules with ensuring that the conversion to energy occurs before transmission constraints are relaxed.

Penalty Price Description	Scheduling Run Value[46]	Pricing Run Value	Comment
Conditionally unqualified Reg Up or Down self-provision	-195	NA	In instances where AS self-provision is not qualified pursuant to the MRTU tariff, the capacity can still be considered as an AS bid, along with regular AS bids. The price used for considering unqualified AS self-provision is lower than the AS bid cap, to allow it to be considered as an Economic Bid.
Conditionally unqualified Spin self-provision	-170	NA	Same as above.
Conditionally unqualified Non-Spin self-provision	-155	NA	Same as above.

Residual Unit Commitment (RUC) Parameter Values

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Transmission constraints: Intertie scheduling	2000	250	The Intertie scheduling constraint retains higher relative priority than other RUC constraints.
Market energy balance - under procurement	1600	0	The RUC procurement may be less than the Demand forecast if the CAISO has committed all available generation and accepted intertie bids up to the intertie capacity.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
Gas-burn nomogram	1250	250	In the scheduling run, the market optimization enforces gas-burn constraints up to a point where the cost of enforcement (the "shadow price" of the constraint) reaches the parameter value, at which point the constraint is relaxed.
Maximum energy limit in RUC schedule	1500	250	Limits the extent to which RUC can procure energy rather than unloaded capacity to meet the RUC target. For MRTU launch the limit will be set so that the total energy scheduled in the IFM and RUC will be no greater than 99% of the RUC target unless this limit is relaxed in the RUC scheduling run.

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.
Day-Ahead energy schedules resulting from the IFM run	250	0	These values preserve schedules established in IFM in both the RUC scheduling run and pricing run.
Market energy balance -over procurement	200	0	Market energy balance when the RUC procurement may be more than the Demand forecast.

Real Time Market Parameters

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
Energy balance/Load curtailment and Self-Scheduled exports utilizing non-RA capacity	6500	1000	Scheduling run penalty price is set high to achieve high priority in serving forecast load and exports that utilize non-RA capacity. Energy bid cap as pricing run parameter reflects energy supply shortage.
Transmission constraints: Intertie scheduling	7000	1000	The highest among all constraints in scheduling run, penalty price reflects its priority over load serving. Energy bid cap as pricing run parameter reflects energy supply shortage.
Reliability Must-Run (RMR) pre-dispatch curtailment (supply), and Exceptional Dispatch Supply	-6000	-150	RMR scheduling requirement is protected with higher priority over enforcement of internal transmission constraint in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Pseudo-tie layoff energy	-6000	-150	Same priority of protection as RMR schedule in scheduling run. Energy bid floor is used as the pricing run parameter for any type of energy self-schedule.
Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1500	1000	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $ of congestion relief in $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
			a global energy supply shortage.
Gas-burn nomogram	1500	1000	Scheduling run penalty price will enforce gas-burn constraints up to a re-dispatch cost of $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage
Real Time TOR Supply Self Schedule	-5900	-150	In RTM, TOR self-schedule scheduling run penalty price is much higher in magnitude than generic self-schedule but lower than transmission constraint. Energy bid floor is used as the pricing run parameter as any type of energy self-schedule.
Real Time ETC Supply Self Schedule	-5100 to -5900	-150	In RTM the range of penalty prices for different ETCs supply self-schedules are much higher in magnitude than generic supply self-schedules but lower than TOR. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Ancillary Service Region Reg-Up and Reg-Down Minimum Requirements	2500	250	Scheduling run penalty price is below the one for transmission constraint. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Spin Minimum Requirements	2250	250	Scheduling run penalty price is lower than the one for regulation-up minimum requirement. Pricing run parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Non-Spin Minimum Requirements	2000	250	Scheduling run penalty price is lower than the one for spin minimum requirement. Pricing parameter is set to the AS market bid cap to reflect AS supply shortage.
Ancillary Service Region Maximum Limit on Upward Services	1500	250	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.
Self-scheduled exports not using identified non-RA supply resource	1050	1000	Scheduling run penalty price reflects relatively low priority in protection as compared to other demand categories. Energy bid cap as pricing run parameter

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
			to reflect energy supply shortage.
Final IFM Supply Schedule	-1000	-150	Scheduling run penalty price is much higher in magnitude than supply generic self-schedule but lower than ETCs. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Regulatory Must-Run and Must Take supply curtailment	-1300	-150	Scheduling run penalty price reflects the higher priority of regulatory must-run and must-take supply received over generic self-schedules for supply resources. Energy bid floor is the pricing parameter for all energy supply self-schedules.
Price-taker supply bids	-1100	-150	Energy bid floor is the pricing parameter for all energy supply self-schedules.
Qualified Load Following self-provision Up or Down	-8500	0	Scheduling run penalty price reflects the highest priority among all categories of AS self-provision. AS bid floor is used as the pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Reg Up or Down Award	-7750	0	Scheduling run penalty price is higher than the penalty price for energy balance constraint to reflect higher in priority over energy. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Spin Award	-7700	0	Scheduling run penalty price is lower than the one for Reg-up. AS bid floor is pricing parameter for any type of AS self-provision.
Day ahead conditionally qualified Non-spin Award	-7650	0	Scheduling run penalty price is lower than the one for Spin. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Reg Up or Down Real Time self-provision (RTUC only)	-405	0	Scheduling run penalty price allows the conversion of AS self-schedules to Energy to prevent LMP of local area from rising so high as to trigger transmission constraint relaxation. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Spin self-provision (RTUC only)	-400	0	Scheduling run penalty price is below the one for regulating-up. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally qualified Real Time Non-Spin self-provision	-395	0	Scheduling run penalty price is below the one for spin. AS bid floor is pricing

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
(RTUC only)			parameter for any type of AS self-provision.
Conditionally unqualified Reg Up or Down Real Time self-provision (RTUC only)	-195	0	In scheduling run, AS self-provision not qualified in pre-processing can still be considered as an AS bid with higher priority in the Energy/AS co-optimization along with regular AS bids. AS bid floor is pricing parameter for any type of AS self-provision.
Conditionally unqualified Spin Real Time self-provision (RTUC only)	-170	0	Same as above.
Conditionally unqualified Non-Spin Real Time self-provision (RTUC only)	-155	0	Same as above.
System power balance constraint	1100, -155	1000, -155	To reflect the role regulation plays in balancing the system when economic bids are exhausted, the ISO allows the system power balance constraint to relax by as much as +/-350MW in the real-time dispatch process. The prices are selected to allow for coordinated dispatch of bids that may exist at or near the bid cap, or at or near the bid floor.
Power Balance constraint for individual PACE and PACW areas.	1100, -750	1000, -150	Subject to the FERC order granting waiver of tariff sections 27.4.3.2.and 27.4.3.4, and consistent with Section 10.1.6 of the BPM for Energy Imbalance Market, which implement the price discovery mechanism overriding the pricing parameters and yielding the last economic signal under constraint relaxation. The scheduling run parameter is set to -750 for the individual EIM areas to coordinate the relaxation of the EIM power balance constraint during over-generation conditions relative to congestion on non-EIM constraints.
EIM Transfer Constraint	1500	1000	Penalty price and pricing parameter consistent with the transmission constraint;
EIM Entitlement Rate of Change Constraint (RTD Only)	1500	0	Penalty price aligned with EIM transfer constraint is currently applicable to RTD 5 minute rate of change.
Flexible Ramping Constraint	60	60	The penalty price used to reflect the price at which the ISO will relax the constraint

Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
for ISO			and procure flexible ramping capacity.
Flexible Ramping Constraint for individual PACE and PACW areas	60	0 or near 0	Set to implement the FERC order granting waiver of tariff sections 27.4.3.2.and 27.4.3.4, and consistent with Section 10.1.6 of the BPM for Energy Imbalance Market, which implement the price discovery mechanism overriding the pricing parameters and yielding the last economic signal under constraint relaxation.

Number 7

A6.5.3   Competitive Path Criteria

This is based on CAISO Tariff Sections 39.7.2.2 and 39.7.3.

As part of each MPM run, an in-line dynamic competitive/non-competitive designation calculation (dynamic competitive path assessment or DCPA) determines whether a constraint is non-competitive.   A Transmission Constraint will be competitive by default unless the Transmission Constraint is determined to be non-competitive as part of this calculation. This will occur when the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow.

If, for some reason, the DCPA is unable to function, the MPM will rely on a default competitive path list which is compiled based on historical analysis of congestion and previous DCPA results on each Transmission Constraint.

The effect of enforcement of gas usage nomograms is not modeled in the DCPA. Therefore, the DCPA will not be able to account for the impact of reduced counter-flow from generators subject to nomogram constraints. When gas nomograms are enforced in the market, the CAISO will deem constraints as non-competitive when a gas nomogram is predicted to create conditions in which the maximum available supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow on that constraint. First, the CAISO will identify the set of Transmission Constraints that can be relieved by counter-flow from potentially gas-limited resources. Then, the CAISO will estimate changes of the residual supply index (RSI) for each of those constraints resulting from gas nomograms of reflecting varying levels of restrictions on gas supply. Estimation of the RSI will involve identical calculations to the ones used in the market, but will use estimates of available capacity when a gas nomogram constraint is in place. The CAISO may designate a constraint or set of constraints non-competitive when the RSI is predicted to be non-competitive when a gas nomogram is imposed in the market.

Over time, the CAISO will develop a table that will identify the potentially non-competitive Transmission Constraints that CAISO operations may deem as non-competitive in the market based on imposition of a particular nomogram under various supply and demand conditions. For each constraint and nomogram combination, a limit or limits will be listed. If a gas nomogram is binding at a level listed on the table, it will be appropriate to declare the listed constraints non-competitive. The CAISO will continue to communicate data related to market power mitigation and the enforcement of gas usage constraints according to current procedures for both of these processes. A constraint deemed non-competitive through the manual override process based on the imposition of a gas supply nomogram will be included in the listings of constraints with competitive designation status provided on the CAISO OASIS site (http://oasis.caiso.com) in the reports MPM Nomogram/Branch Group Competitive Paths and MPM Intertie Constraint Competitive Paths. These reports are described in further detail in the BPM for Market Instruments, Section 12 Public Market Information.

For a detailed process description for the dynamic competitive path criteria, Refer to Attachment B

Number 10

A2.5.2.4 Virtual Bids

"Convergence" or Virtual Bids are financial bids submitted only in the Day-Ahead Market. The Integrated Forward Market (IFM) clears Virtual and physical Bids in a non-discriminatory manner. If cleared in the IFM, the resulting Virtual Supply and Virtual Demand Awards would

settle first at the locational Day-Ahead LMP and then be automatically liquidated with the opposite sell/buy position at the simple average of the four applicable FMM LMPs.

Convergence bidding provides Market Participants with several financial functions. First, there is the opportunity to earn revenues (and to risk losses) resulting from any differences in the Day-Ahead and FMM LMPs. Market Participants, using their insights into system and market conditions, may be able to identify Virtual Bidding opportunities that result in more efficient market outcomes. The potential for financial reward encourages Virtual Bidding activity that would tend to minimize any systematic differences between Day-Ahead and FMM LMPs, thus minimizing incentives for under or over-scheduling physical Demand in the Day-Ahead Market. A generator owner can also use a Virtual Bid to mitigate the risk impact of an outage that happens after the close of the Day-Ahead Market. By increasing market liquidity through Virtual Bidding, the potential for the exercise of market power also decreases.

Virtual Bids are explicitly flagged as Virtual Bids when submitted to the Day-Ahead Market. Their submission and processing includes an indicator that identifies them as Virtual Bids rather than physical Bids. This indication 1) allows for their exclusion from the automated Local Market Power Mitigation process; 2) allows the Virtual Bids to be tracked and associated with the Convergence Bidding Entity; 3) allows the CAISO to be able to suspend Virtual Bids by location or by Convergence Bidding Entity when necessary[47], the ISO will issue a technical bulletin on the justification for a general suspension or limitation of Virtual Bids related to Aliso Canyon gas coordination modeling or operations; and 4) allows the CAISO to exclude Virtual Bids from the RUC market.

---

[47] The CASO has the authority to suspend or limit Virtual Bids pursuant to Tariff Sections 7.7.15. and 7.9.